POTENTIAL BENEFITS AND COSTS OF CANADIAN ELECTRICITY EXPORTS

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ABSTRACT

The study investigates the potential benefits and costs of increased Canadian electricity exports to the United States. These benefits are identified through integrating analysis of the potential size of the U.S. market, the cost of Canadian supply, the opportunity cost of U.S. generation, and illustrative export pricing rules and volumes. The U.S. markets investigated encompass the displacement of new capacity and existing oil-fired generation. Prospective Canadian supply sources comprise dedicated and surplus capacity. The regional income and employment impacts of increased electricity exports are then assessed with some comparison to the economic impacts of increased exports of other commodities. Legal or regulatory issues and the environmental costs arising from international electricity trade are discussed. Finally, the study presents a number of constraints associated with increased electricity exports and provides some recommendations on how to alleviate these constraints.

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PREFACE

This study was conducted for the Canadian Electrical Association (CEA Agreement #021-G-209) between February, 1981 and October, 1982. Gordon Gislason was responsible for integrating the demand analysis of Chapter 3 and for general organization of the study. Ellen Battle performed the supply analysis of Chapter 4, while Gordon Douglas was responsible for the economic impact analysis of Chapter 5.

We would like to thank the many utility representatives who provided data and helpful comments throughout the preparation of this report. Special thanks go to the CEA Steering Committee chaired by Don Priestman (B.C. Hydro) and also comprising Eric Hansen (Manitoba Hydro), Michael Agrell (Ontario Hydro), Martin Warnes (Energy, Mines and Resources Canada), Marie-Bernard Guertin (Hydro-Quebec) and Lin Titus (New Brunswick Electric Power Commission). The Committee put considerable time and effort into reviewing drafts of the report. We would also like to thank Paul Simon and David Drinkwalter, both of Ontario Hydro, for their useful comments at earlier stages. In addition, we benefited substantially from the review of results presented to the Economics Section of the CEA, Fall Meeting, September 1982.

The demand analysis of Chapter 3 and much of Appendices C through F are based on work undertaken by Martin Baughman of Southwest Energy Associates, Inc. (Austin, Texas). Mr. Baughman also provided general assistance during the study. Al Lucas and Owen Saunders of the Canadian Institute of Resources Law (University of Calgary, Alberta) prepared the appendix on legal and regulatory issues (Appendix A).

We would like to extend our sincere thanks to Janice Tener for her industriousness, enthusiasm and patience in typing and bringing together this report for circulation. Thanks also go to Shirley Ingstrup, Arlene Ward, and Carol Williams for their typing assistance. Russ McNab was responsible for the computer programming in Chapter 4 and graphics were undertaken by Jeanette Palin, Tim Crocker and Brady Sakon. Gerry Angevine, Jim MacMillan and Alan Webster provided internal review. Finally, we would like to thank former staff-members Gerry Protti and Ken Foat for their contributions at the inception of this study. However, the views and opinions expressed herein are those of the authors, who accept responsibility for any errors or omissions that may exist.

EXECUTIVE SUMMARY

The recent growth in Canadian electricity exports to the United States has sparked considerable interest and debate on the part of electric utilities, governments and the public at large. Participating utilities have long been aware of the benefits of these exports including seasonal diversity interchange, emergency backup, reduced oil consumption and regional economic benefits. However, utilities have encountered some difficulty in demonstrating to the public the overall benefits of electric power exports.

The purpose of this study is to identify and, where possible, to quantify the costs and benefits of increased electricity exports. Specific study areas include:

- the potential net economic benefits to exporting utilities;
- the potential regional and national economic impacts of electricity exports, with some comparison to those of other export commodities; and
- the environmental, legal, regulatory and other important implications of greater levels of power exports.

Information of this nature can be used in determining whether increased exports would significantly benefit private citizens, electric utilities and their customers, and the regional and national economies.

Five Canadian provinces--New Brunswick, Quebec, Ontario, Manitoba and British Columbia--have a history of electricity exports to the United States. The majority of these exports have been short-term interruptible sales from surplus energy in provincial systems, and have been made to displace higher cost generation or to provide emergency assistance. Recently, however, utilities in states stretching from New England to California have expressed an interest in long-term firm imports. U.S. utilities have been looking to imported electricity for several reasons: the cost advantage which Canadian power demonstrates in many instances, the financing and regulatory difficulties which American utilities have experienced in undertaking their own construction programs, and the U.S. national energy policy of displacing foreign oil. In response, a number of exporting provinces have announced their willingness to consider building generating capacity in advance of provincial needs, with a view to serving those export markets. This would entail construction of facilities which would be 'dedicated' in whole or in part for periods up to their useful lives.

A spectrum of U.S. markets would be available to Canadian utilities. Among these potential markets are:

- the long-term displacement of new (coal-fired or nuclear) base load capacity;
- the long-term displacement of existing (intermediate to base load) oil-fired generation;
- the long-term displacement of new capacity through seasonal diversity interchange;
- the short-term displacement of existing higher cost generation (i.e., the market for interruptible energy which has been the principal market to date);
- the long-term displacement of existing base load coal-fired generation; and
- the market for firm capacity to displace peaking generation.

The first three markets are analyzed quantitatively in this study. The fourth market is addressed qualitatively and, for purposes of calculating potential net benefits to Canadian utilities, is assumed to be supply-side determined. A unique feature of the analysis of long-term oil displacement is that a computerized simulation model of the U.S. electric utility industry (the Regionalized Electricity Model) is used to estimate regional demand functions for blocks of Canadian electricity. The potential demands for capacity displacement are determined by examining U.S. utility expansion plans. Potential seasonal diversity demands are derived by matching Canadian and U.S. seasonal peak demand profiles by region.

Our analysis indicates that for the study year 2000 the potential size of these three markets would be as presented in Table I. Results are shown for two U.S. demand growth scenarios. With the downward trend in average annual load growth forecasts, most U.S. utility projections are currently running in the low (2.0 percent per year) to mid (3.1 percent per year) growth range for the 1980 - 2000 period.

TABLE I

POTENTIAL MARKETS FOR CANADIAN ELECTRICITY EXPORTS[a] (megawatts)

	Capacity Displacement		Oil Displacement		Diversity Interchange	
	Demand Growth		Demand Growth		Reserve Criterion	
	Low	Mid	Low	Mid	25%[b]	20%
New England	4 000	6 000	2 000+	5 000	-	-
New York	3 000	2 000	-	5 000	-	1 000
MAAC	5 000	7 000	-	5 000	5 000	8 000
MAIN	7 000	23 000	-	-	2 000	6 000
ECAR	20 000	42 000	-	-	-	-
MARCA	6 000	14 000	-	1 000[c]	-	2 000
Pacific Northwest	9 000	18 000	-	-	-	-
California-Nevada	8 000	21 000	5 000+	10 000	-	3 000
Southwest	7 000	10 000	small	small	-	-
TOTAL	70 000	142 000	7 000+	26 000	7 000	20 000

[a] Totals may not add due to rounding.

[b] Assumes 5 percent higher reserve margin under integrated operation.

[c] Includes other higher cost (intermediate load to peaking) capacity than oil.

In order to determine the value of exports to Canadian utilities, promising markets are identified across regions and market types according to three criteria: 1) potential market size; 2) potential net benefits per kilowatt-hour sale; and 3) reliability considerations. Prospective exporters could serve U.S. demands from surplus domestic capacity or from facilities constructed specifically for export (i.e., export-dedicated facilities). While several different types of transactions could be arranged between exporting and importing utilities, for study purposes we consider:

- dedicated exports to displace new capacity;
- dedicated exports to displace existing oil-fired capacity;
- interruptible energy to displace existing oil-fired capacity; and

- seasonal diversity interchange.

Canadian provinces are selectively matched with attractive American markets, and utility cost data and U.S. replacement costs are used to calculate potential net benefits from export. This analysis is strictly illustrative in the sense that it does not attempt an optimal matching of markets and supply sources, at either the utility or national level. Furthermore, hypothetical pricing rules and export volumes are adopted. Dedicated exports are priced at the full U.S. replacement cost, while interruptible sales are priced mid-way between U.S. replacement cost and Canadian delivered cost. Of course, in practice the price for dedicated exports would most likely fall below U.S. replacement cost because the purchaser would expect some form of cost saving over domestic generation.

Taking into account the possible overlap in markets (e.g., in the market for oil displacement), our estimates suggest potential net revenues to Canadian utilities in excess of 2 billion dollars ($1980) annually by the year 2000 (see Table II). This corresponds to over 4 billion dollars per year in total export revenues, roughly four times actual 1981 electricity export revenue total of 1.1 billion dollars ($1981).

On the basis of the three criteria outlined above, the most promising markets for Canadian electricity are the oil-dependent regions of New England, New York, MAAC (Pennsylvania, Maryland, etc.) and California-Nevada. Particularly for California and the New England states, this long-term oil displacement market remains buoyant under assumptions of lower demand growth. Oil dependent markets could be economically accessed by all Canadian provinces except Prince Edward Island, if transmission capability were adequately increased. In terms of the tradeoffs between dedicated and interruptible exports, interruptible energy offers the opportunity to earn revenue from surplus capacity, without a 'tying up' of Canadian generation resources. Dedicated exports, on the other hand, could provide a means of securing U.S. markets into the future, in the face of uncertainties with respect to load growth and competive supply sources.

In comparison to the market to displace existing oil-fired generation, the capacity displacement and diversity interchange markets are found to be less attractive. Although in each case the potential market size is significant, the net benefits available to the exporting utilities are considerably smaller on a unit (i.e., per kilowatt-hour) sale basis. The reason is that, for most U.S. regions, the marginal

POTENTIAL NET BENEFITS TO CANADIAN UTILITIES FROM INCREASED ELECTRICITY EXPORTS BASE CASE YEAR 2000 - 1000 MW ILLUSTRATIVE SALE (1980 $Millions Canadian)

U.S. Region/ Province	Capacity Displacement	Oil Displacement			Diversity Interchange	
	Dedicated	Dedicated		Interruptible	25% Reserve	20% Reserve
	Low or Mid[a]	Low	Mid	Low or Mid		
New England						
Newfoundland	140	480	390	N/A[b]	N/A	N/A
Nova Scotia	N/E[c]	220	220	N/A	N/A	N/A
New Brunswick	40	350	290	190	N/A	130[d]
New York						
Quebec	80	40[e]	340	200	80	80[d]
Ontario	90	50[e]	340	190	110	110[d]
MARCA						
Manitoba	70	100[e]	140	170	N/A	30
Saskatchewan	N/E	60[e]	90	N/A	N/A	N/A
California-Nevada						
Alberta	N/E	280	280	N/A	N/A	N/A
British Columbia	N/E	440	400	210	N/A	30
TOTAL	420	2020	2490	960	190	380

[a] U.S. demand growth scenarios correspond to 2.0 percent and 3.1 percent per year over 1980 - 2000 period.

[b] Not Applicable (i.e., only considered for selected provinces).

[c] Not Economic.

[d] New Brunswick, Quebec and Ontario matched with New York, MAAC and MAIN, respectively, for Diversity Interchange.

[e] Market not identified in demand analysis because 1000 MW demanded at capacity factor less than 50 percent.

(i.e., operating) cost of oil-fired generation is anticipated to be double the average (i.e., capital plus operating) cost of new coal-fired or nuclear capacity. Under the U.S. replacement cost pricing rule used, this results in smaller potential net revenues for any given export volume. In addition, the latter two export types could entail a stricter reliability of supply criterion, since U.S. utilities would be foregoing the installation of domestically owned and operated capacity.

Possible constraints on the ability of Canadian utilities to further penetrate U.S. markets include transmission capability, environmental considerations, competition from U.S. utilities, regulatory restrictions and political opposition. Based on present knowledge, it appears that imputing a reasonable value to environmental and health costs would not jeopardize the feasibility of oil-displacing exports, although it would reduce the level of potential net benefits.

Assuming that these constraints could be overcome, the net revenues from increased electricity exports could be applied towards a number of uses such as:

- a reduction in domestic electricity rate structures;
- a lowering of external financing requirements for capacity expansion, so that future rate increases could be reduced;
- a contribution to special funds for conservation, environmmental mitigation, etc.; and
- appropriation and recycling by the government through taxation.

Besides generating revenue for utilities and governments, increased electricity exports could have a significant effect on the regional and national economies. We use the Statistics Canada Interprovincial Input-output model based on 1974 interindustry relationships to provide consistent estimates of the economic (income and employment) impacts of exports of electricity and other commodities across provinces. Since this model incorporates the capital costs as well as the operating costs of electricity generation, its results more accurately represent the impacts of dedicated and firm power exports than those of interruptible exports. In addition, the analysis tends to underestimate the true economic impact of exports since it excludes stimulus to government activity and capital investment, and opportunities for import substitution. For the 1980 study year, the total regional and national economic impacts of a $1 million rise in electricity export demand are estimated to be as shown in Table III.

TABLE III

ECONOMIC IMPACT OF $1 MILLION ELECTRICITY EXPORT DEMAND

	Income (thousands of 1980 dollars)		Employment (man-years)	
	Provincial	Canadian	Provincial	Canadian
Newfoundland	950	1080	7	10
Nova Scotia	760	1040	16	23
New Brunswick	750	1030	13	20
Quebec	1110	1240	13	16
Ontario	1110	1200	15	16
Manitoba	1110	1290	14	17
Saskatchewan	990	1250	12	17
Alberta	1100	1240	12	15
British Columbia	1130	1260	14	16

On the basis of our province-by-province analysis of selected export commodities, we conclude that the income impacts of increased power exports compare favourably with those of other exports. In terms of total Canadian income impact, electricity exports show a greater impact than do aluminum or automobile exports but a lesser impact than exports of fish products or lumber and paper. A greater proportion of the electricity income impact remains in the province of origin, with the result that the total regional income impact of an increment in electricity export demand exceeds that of most other commodities considered. Because of its capital intensive nature, electricity demand gives rise to a lesser employment impact than other industry demand, particularly in the case of hydro provinces. However, compared to other export industries like primary metals and forest products, electricity exports display favourable market conditions and significant growth potential.

It is sometimes argued that direct electricity exports, as opposed to 'embodied' electricity exports from energy intensive industries (e.g., aluminum), lead to an 'export of jobs' from Canada. However, the development of the electricity export industry and other manufacturing industries could proceed on a complementary basis given the country's surplus situation with respect to existing generating capacity and undeveloped generation resources. Furthermore, other regional industries could in fact be stimulated through the application of export revenue to reduce domestic electricity rates.

Another macroeconomic impact of greater electricity exports concerns their effect on balance of payments. In the short term, increased exports would help to offset Canada's rising oil trade deficit. In the long term, electricity exports could grow to reduce substantially or perhaps even to eliminate that deficit. Balance of payments considerations, however, are not as important as the ultimate effects of exports on income, employment and other economic indicators.

Among the other potential benefits of increased exports is the possibility of building generation facilities in advance of domestic needs, dedicating them to export markets over the medium to long term, and then repatriating them when the power is required in province. This 'prebuild option' could offer such benefits as savings in rising construction costs, economies of scale for smaller utilities, a greater flexibility in utility planning, and diversification of Canada's long-term energy options. Prebuilt nuclear stations would also stimulate the domestic CANDU nuclear industry. The federal government and several provinces (e.g., New Brunswick, Quebec, Ontario and Manitoba) have endorsed the prebuild concept but in other provinces the policy on building for export in advance of domestic requirements is less favourable or clear.

The National Energy Board has maintained an encouraging stance with respect to electricity exports. In its regulatory role, the Board protects the Canadian interest by stipulating that exports must be surplus to foreseeable domestic needs and that export prices must be 'just and reasonable'. The terms of export licences can incorporate predetermined curtailment or interruption conditions. However, the NEB has never terminated an electric power export licence, and Canada has maintained a stable electricity licensing policy since 1963. Moreover, Canada has explicitly exempted electricity from its newly acquired powers to revoke export licences on grounds of 'public convenience and necessity'. It is our opinion that government curtailment is unlikely since such an action could have adverse long-term repercussions on U.S. markets for Canadian products.

In assigning national priorities to potential sources of export supply, attention must be given to economic, environmental and energy policy criteria. On the basis of the analysis in this study, we find that generally hydroelectric power exports produce the greatest net economic benefits to Canadian utilities, followed closely by nuclear power exports, and finally by coal-fired electricity exports. However, regional differences in resource endowments, supply costs (including transmission) and energy policy criteria may suggest a different ranking of hydro and nuclear power exports within a particular province.

Ultimately, a decision on whether to pursue increased electricity exports calls for value judgements on the part of policymakers. The associated costs and benefits must be carefully weighed, and to the extent that this strategy has not been applied consistently across exporting industries, government policy may require some reassessment.

Based on the analysis conducted in this study we recommend the following:

- A more vigorous export policy would be in the national interest and therefore should be further investigated by electric utilities and governments;
- Provincial governments should reassess their policies concerning firm electricity exports in light of the benefits demonstrated and given the pessimistic economic outlook over the next few years;
- In view of some U.S. misconceptions concerning Canadian regulatory powers, the Canadian government should undertake an extensive information campaign to convince U.S. utilities of Canada's willingness to enter into contractual agreements for firm electric power sales;
- A national policy of increased electricity exports should be considered in conjunction with greater interprovincial power transfers;
- The electric utility industry should develop a consistent approach and strategy vis-a-vis power sales to the United States and individual utilities should work together to eliminate misunderstanding on the part of governments and the general public; and
- The Canadian government should take the lead in establishing an institutional framework for increased electricity exports by exploring the potential legal, financial and other arrangements of export.

Chapter 1

INTRODUCTION

In the last few years, electric utilities and governments on both sides of the border have been seeking increased exports of Canadian electricity to the United States. Between 1977 and 1981, the revenue from net Canadian power exports grew from 406 to 1138 million dollars.[1] Besides providing a source of income, this rising electricity trade has allowed Canada to participate in seasonal diversity exchanges[2] with summer peaking utilities to the south. Americans, for their part, have received reliable power for emergency backup and for the displacement of high cost electricity generated from fossil fuels.

Recently, the outlook for higher levels of export has been enhanced by financial and regulatory developments in the United States. Many U.S. utilities are trimming their capital expenditure programs due to inflation, high interest rates, and rate-setting procedures which have not allowed rates of return to rise in keeping with the cost of capital. In addition, licensing delays are leading to the deferral or cancellation of generation projects--in particular, nuclear power projects--in U.S. expansion plans. This, in turn, could influence the industry's ability to provide low cost reliable service and, moreover, to reduce its dependence on imported oil.[3] As a result, American producers are turning increasingly to Canadian utilities to serve part of their future power requirements, and not just through the short-term interruptible purchases which have characterized Canadian/U.S. electricity trade in the past. Today, utilities in states stretching from Maine to Wisconsin are actively pursuing long-term firm power imports to substitute for the installation of generating capacity at home.

In response, each of Canada's current electricity exporters--New Brunswick, Quebec, Ontario, Manitoba and British Columbia--has been looking more closely at these promising U.S. markets. With the downward trend in North American load growth, most provincial utilities are finding themselves with considerable surplus capacity. This surplus could be exported to the United States given adequate transmission capability. There is also growing interest in the notion of building capacity in Canada solely for export purposes ('export-dedicated facilities') and of building in advance of domestic needs to serve medium-term U.S. markets (the 'prebuild option').

Whether such innovative modes of export, or increased conventional electricity exports, are acceptable depends to a large extent on public and political perceptions regarding the net social benefits at the local, regional and national levels. In the past, public support for power exports has been influenced by concerns about Canadian security of supply and adverse environmental impacts.

The general controversy surrounding electricity exports has given rise to a number of studies which have explored the advantages and disadvantages of Canadian/U.S. power interconnections.[4] In January 1978, Prime Minister Trudeau and then Vice President Mondale agreed to examine jointly the potential for increasing electricity exchanges. An ensuing report, Canada/United States Electricity Exchanges,[5] described the opportunities and incentives, as well as the obstacles and constraints, to such exchanges.

The purpose of this study is to build on the export discussion to date by providing a quantitative analysis of the potential demand for and supply of Canadian power exports. The specific study objectives are:

- to estimate the potential economic costs and benefits of increased electricity exports;
- to estimate the potential regional and national economic impacts from the export of electric power, with some comparison to the economic impacts of other export commodities; and
- to identify and discuss other important areas of concern such as the environmental and legal implications of higher levels of export.

It is hoped that this information on the potential economic returns from export and on the associated economic impacts will be useful to Canadian policymakers in determining whether increased electricity exports would significantly benefit private citizens, electric utilities, and the national and regional economies.

The remainder of this chapter will outline the key issues associated with greater exports, drawing primarily on the joint Electricity Exchanges report mentioned above. In addition, the study terminology and structure will be clarified. It should be noted that all aspects of the electric power trade (generation planning, government policy, etc.) are highly dynamic in nature. The background provided in this and following chapters is current to August 1982.

1.1 Increased Electricity Exports: The Issues

1.1.1 Benefits and Costs of Electricity Exports to Canadian Utilities and Their Customers

Revenue

Exports generate revenue which may be used to lower domestic costs of service. To the extent that this revenue goes toward reducing rate structures, domestic customers receive a direct and immediate benefit. Alternatively, export revenue may be allocated to system expansion. This can result in a softening of future rate increases and a lowering of external financing requirements such that utilities can ease their burden of high interest rates from borrowing in financial markets.[6] The potential (net) revenues available from export sales are analyzed in Chapter 4, while the possible applications of these revenues are addressed in Chapter 6.

Capital Cost Savings

In addition to earning revenue, exporting utilities can save on capital costs in a number of ways. By participating in seasonal diversity interchange, a utility may be able to reduce its required level of installed capacity, and thus trim its construction program (see below under 1.2.3). Another form of cost saving is available in the prebuild option, whereby generating facilities would be constructed to supply U.S. customers until Canadian demand warranted 'repatriation' of the power. For smaller utilities, this could mean the opportunity to realize certain economies of scale inherent in building for an expanded market. More generally, capital cost savings would accrue over a period in which construction costs were rising faster than interest rates. The advantages of prebuild facilities will be discussed further in Chapter 6.

Uncertainty

All electric utilities face uncertainty in their planning process, particularly with respect to demand growth. Load growth forecasts have been adjusted downwards to reflect a new environment of slower economic growth, higher energy prices and increased conservation. Therefore, some Canadian provinces are faced with the prospect of significant overcapacity for the duration of the 1980s. Export markets can provide a lucrative outlet for surplus capacity and energy production capability (see Chapter 6). But this domestic demand-side uncertainty is a double-edged sword in the sense that it could make Canadian utilities reluctant to commit themselves to long-term export contracts. Exporters might have to resort to more expensive generation for an unanticipated rise in in-province demand, if lower cost capacity and energy were tied up in firm export sales.

Reliability

A general characteristic of interconnections is that they tend to improve reliability and to reduce required reserve margins (the percentage difference between generating capacity and expected peak demand).[7] A lower reserve margin is possible because the interconnected regions can pool their generating resources to lessen the likelihood and impact of generator outages on the system. This in turn can lead to reduced construction programs and more efficient use of installed capacity. At the same time, the larger the system the greater the potential for 'cascading', a phenomenon whereby minor disturbances are translated into major outages over large areas of the network. However, this problem can be alleviated by installing equipment to shed loads or break interties in times of emergency.[8] Moreover, it is unlikely to outweigh the advantages of strengthened interconnections.

Generation and Transmission Costs

A significant increase in electricity exports could involve capital outlays on new generating plants, new transmission lines and transmission reinforcement. Historically, Canadian utilities have experienced fewer financing difficulties than their investor-owned American counterparts because provincial governments have guaranteed their bond issues. Recently, however, inflation and increased risk have put considerable pressure on the industry's ability to finance capital intensive generation projects. When it comes to exports, a number of financing proposals have been made which could act to ease these financial constraints. For example, it has been suggested that export-dedicated nuclear plants could be financed through some combination of federal and provincial equity and long-term export contracts designed to cover costs of production.[9] Authorities in New England have been recommending direct investment in Quebec's vast hydroelectric resources. One such proposal calls for 100 percent financing by U.S. utilities, in exchange for commitments of firm power.[10] These sorts of financing schemes would go considerably towards redistributing the risks associated with electricity exports. While acknowledging their importance, this study does not address the detailed financial, or contractual, arrangements of a more active export policy.

Environmental and Land Use

Like other industries, the production of electricity can carry with it adverse environmental and land use impacts. Among these potential impacts are flooding from hydro dams, danger to health from the storage and long-term disposal of nuclear waste, acid rain fallout from coal-fired facilities, and destruction of the scenic landscape by transmission lines. Environmental opposition is likely to be stronger when electricity is being produced for export. In fact, some people maintain that exports from coal-fired or nuclear stations are tantamount to imports of pollution and other environmental risks from the United States. On the controversial acid rain issue, utility representatives provide the counter argument that Canadian exports could minimize environmental damage by displacing old coal-fired units in the northeastern states.[11] Environmental, health and land use issues will be discussed in Chapter 6.

1.1.2 Benefits and Costs of Canadian Electricity Exports to Canada as a Whole

The Regional and National Economies

Electricity exports can generate income and employment both in the exporting region and elsewhere in Canada. For example, the construction of an export-dedicated nuclear plant in Ontario or New Brunswick would stimulate activity in the Canadian nuclear, uranium mining and manufacturing industries, in addition to the local construction and service industries. Similarly, exports based on the use of Canadian thermal coal would increase employment in the coal-rich regions of the country such as Nova Scotia, Saskatchewan, Alberta and British Columbia. Chapter 5 addresses the potential economic impact of increased electricity exports, with comparison to the impacts of other export commodities. It is sometimes argued that electric power sales to the United States constitute an 'export of jobs' since the power could be preserved for use by domestic manufacturing industry. To the extent that there is competition for factors of production (capital, labour, land, energy), the trade-offs between electricity and other exports involve a consideration of employment impacts, international market conditions, industry growth potential, and other factors.

Balance of Payments

An advantage of electricity exports which is often cited concerns their role in offsetting Canada's oil trade deficit (see Chapter 5). The revenue from such sales tends to improve our balance of payments by increasing the inward flow of funds in payment for the exports. If export revenue is then earmarked for system expansion, the balance of payments may also benefit from reduced debt payments to foreign creditors.[12]

1.1.3 Benefits and Costs of Canadian Electricity Exports to U.S. Utilities and Their Customers

Lower Cost Power

Through imports of surplus power from Canadian hydro, coal-fired or nuclear facilities, several American utilities are able to displace costly oil-fired generation at home. Oil displacement is particularly urgent in the northeastern states (New England and New York) where oil and gas accounted for 59 percent of total thermal generation in 1981.[13] Besides lowering utility operating costs, a cutback in oil-fired generation contributes to the U.S. policy of reducing reliance on foreign oil supplies.

Security of Supply

One concern for prospective American importers is that foreign power might not be as reliable as generation from self-owned and operated facilities. For U.S. producers subject to regulation, the preference for direct ownership is reinforced by a requirement that profit can only be earned on invested capital.[14] However, this regulatory bias has not prevented certain U.S. regions, particularly those reliant on oil-fired generation, from pressing for increased imports. In fact, several New England utilities have even proposed putting equity into nuclear plants in New Brunswick. Perhaps a more important security of supply issue centers on the perception that contracts might be interrupted in the face of unanticipated provincial load growth, power requirements by neighbouring provinces, or governmental action. Further discussion of these issues is provided in Chapter 7 and Appendix A.

Other Benefits and Costs

Several of the benefits to Canadian utilities of increased electricity exports and interconnections could also accrue to purchasing U.S. utilities; examples are those relating to reliability and capacity savings through seasonal diversity interchange. Potential costs and obstacles include economic displacement from the deferral of domestic construction programs, and regulatory and financial constraints on upgrading transmission capability.

1.1.4 Canadian Public Policy Issues

Public and Political Support

Utility and government representatives have experienced some difficulty in securing public approval of electric power exports. Aside from local opposition on environmental grounds, there is a general impression that electricity is a natural resource which should be used to produce manufactured export commodities. (In fact, electricity itself is a manufactured good, with the potential for considerable value added. See Chapter 5.) In some provinces, this lack of support has been reflected in uncertain government policy on the subject of increased exports. However, the federal government and several provinces (e.g., New Brunswick, Quebec, Ontario and Manitoba) have indicated their willingness to consider new avenues into the export field in the form of prebuild generation facilities.

Repatriation

A number of important legal and regulatory issues arise with respect to the repatriation of Canadian electricity that has been committed to export markets. Appendix A examines a subset of these issues pertaining to powers of Canadian governments to curtail contracted exports. These include the regulatory authority of the federal and provincial governments in the electricity export area, compensation rights to affected parties in the event of government curtailment, and obligations under international law that may inhibit government action. These issues could, in turn, influence utility decisions to enter into contracts for electricity exports.

Taxation

The revenue from electric power exports represents an attractive target for taxation, particularly during current economic conditions. Beyond its redistributive impact, the potential for taxation to affect the volume of any prospective export depends upon the specific economics (i.e., profitability) of the transaction and the wording of contracts (see Chapter 6).

National Goals

Increased electricity exports could have implications for Canadian energy policy goals including security of supply, energy self-sufficiency and conservation, as well as other general objectives like the broadening of our industrial base and the development of high technology. These issues are addressed in Chapter 6.

1.2 Study Terminology

A comprehensive list of electricity terminology is contained in the Glossary. At this point, our intention is to discuss the form which increased electricity exports to the United States could assume. In fact, a wide spectrum of transactions are available between Canadian and U.S. utilities depending on a number of interrelated factors such as type of generaton displaced in the U.S. system (e.g., new capacity/old capacity, base load/peaking), conditions of supply (firm/interruptible), duration of sale, and source of generation for export (surplus capacity on the provincial system/'export-dedicated' capacity).

Basically, these many different transactions can be aggregated into three classes.[15] The first such class consists of exports of energy with no capacity commitment. This refers to short-term interruptible sales from a lower cost system to a higher cost system when the purchaser possesses adequate domestic generation. The second class of sale is exports of capacity, with an associated amount of energy which can run from zero (in balance, if it is specified that energy must be returned by the purchaser at a later date) to base load energy requirements. These sales can be designed for a range of uses including short-term emergency backup and long-term capacity displacement, and are firm, meaning that the seller has an obligation to maintain supply. The surplus capacity on the seller's system can result from reserves, planning requirements (e.g., the fact that most hydro systems plan their capacity additions for low water conditions), or a falling off of load growth. The third export class covers exchanges of capacity and energy which arise because of load fluctuations within any given year. Examples are seasonal diversity exchanges between winter peaking Canadian systems and summer peaking U.S. systems, and storage transfer (or 'banking') where off-peak hydro energy is stored by a neighbouring system until required during peak periods.

While recognizing the variety of transactions available, this study focuses for purposes of quantitative analysis on the four types of electricity exports described below.

1.2.1 Dedicated Exports

Dedicated exports are defined herein as sales of capacity and associated energy made under medium or long-term contract from a Canadian facility which has been constructed for the U.S. market.[16] Essentially, it is as if the dedicated unit or units were to become part of the purchasing utility's system, with ownership and operation remaining with the selling utility. The seller provides the agreed capacity but is not responsible for backup facilties in times of generator outages. The purchaser pays the fixed and operating costs of the dedicated units and is entitled to receive capacity at all times (including periods of deficiency in the seller's system) except when supply from the specific units is interrupted. In this way, dedicated exports, as we have defined them, are similar to the 'unit participation agreements' (see Glossary) used extensively in the United States.

Dedicated exports are classified into two types of sale, dedicated capacity and dedicated energy. From the Canadian supply side, there is no distinction between the two. In both cases, the seller must provide a specified block of capacity with no backup requirement. The distinction is made from the U.S. perspective, in terms of the kind of generating capacity which the purchase is used to displace.

Dedicated Capacity

A dedicated capacity sale displaces new (coal-fired or nuclear) base load capacity in the American utility's expansion plan. The purchaser foregoes the construction of domestic generating facilities with the promise of less expensive, but equally reliable, power from Canada.

Dedicated Energy

A dedicated energy sale displaces generation from existing oil-fired capacity in the U.S. region. The assumption is that oil-fired capacity is operated at reduced or zero load levels if lower cost energy is available from Canada. Unlike the above case, the American utility is assumed to possess enough capacity to serve reliably its own demands. Therefore, from the U.S. point of view, the import does not have to meet as stringent a reliability criterion, in the sense that idle oil-fired capacity can always be brought on line in the event of curtailed supply (albeit at a higher cost than the import).

1.2.2 Interruptible Energy

Interruptible energy denotes the sale of surplus energy (i.e., with no capacity commitment) on a short-term, interruptible basis. Like dedicated energy exports, interruptible energy is designed to displace higher cost energy when the importing utility has adequate generation of its own. But, in contrast to the other kinds of power exports considered here, it does not presume an altered supply capability on the part of Canadian utilities. Interruptible power has formed the basis for most Canadian electricity exports in recent years.

1.2.3 Seasonal Diversity Interchange

Seasonal diversity interchange is defined as capacity shared between utilities which experience their annual peak loads during different seasons of the year. Under this type of 'exchange', utilities co-ordinate their system operation and planning to realize capacity savings, as well as any production cost savings, which may result from the interchange of power. The potential for capacity savings arises because the composite load for the two regions may demand a lower level of installed capacity than is required if the regions operate independently. Of course, seasonal exchanges of surplus power are not new. What distinguishes the definition at hand is that the participating utilities specifically defer their construction programs and substitute imported for domestic capacity.[17] In addition, this type of exchange would call for a much greater degree of interdependence between Canadian and U.S. regions than has generally been observed to date.

Again, as potential future types of export sale, the above four classifications are not intended to be comprehensive; that is, other traditional types of sale (e.g., firm capacity or energy. See Glossary.) are expected to continue. Moreover, there is some overlap among the four potential markets such that the demands for them cannot be considered additive. For example, long-term dedicated energy sales could encroach upon the market for short-term interruptible energy to displace oil-fired generation in the United States. Similarly, capacity savings from seasonal diversity interchange could reduce U.S. demand for imports of dedicated capacity.

1.3 Study Structure

In the remaining chapters, some of the issues associated with increased electricity exports will be addressed. Chapter 2 will provide a brief historical background to electricity trade between Canada and the United States. In the next three chapters, the core analysis of the economic benefits and costs of increased exports will then be presented. In Chapter 3, we will estimate the potential U.S. demand, by region, for the four types of sale defined above. Chapter 4 will focus on the potential supply response by provincial utilities to these estimated regional demands. Specifically, potential net benefits will be calculated for each type of export sale. In Chapter 5, we will investigate the economic impact of electricity exports, with some comparison to other export commodities. The effects on national and regional incomes and employment, as well as on balance of payments, will be discussed. Chapter 6 will then link the quantitative analysis in the preceding three chapters to a number of 'non-economic' policy issues introduced in Chapter 1, including environmental impact. Finally, in Chapter 7 study conclusions and recommendations will be presented.

Footnotes

[1] Canada, Department of Energy, Mines and Resources, Electric Power in Canada 1981 (Ottawa: Electrical Branch, 1982), Table 15. (Mimeographed)

[2] Seasonal diversity exchanges refer to power exchanged between utilities which experience their annual peak loads in different seasons (i.e., summer versus winter).

[3] North American Electric Reliability Council, "11th Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems" (Princeton: NERC, August 1981), pp. 4 - 5.

[4] See for example Mark Perlgut, Electricity Across the Border: The U.S. - Canadian Experience (Montreal: C.D. Howe Research Institute, December 1979) and the joint Canadian/U.S. report mentioned below.

[5] Canada, Department of Energy, Mines and Resources and United States, Department of Energy (Ottawa: Energy, Mines and Resources Canada, 1979).

[6] This presumes that exports are made from existing facilities. If exports involve construction of new facilities, as in the case of export-dedicated generating stations, utilities may have to borrow abroad and so increase their long-term debt.

[7] This reliability advantage has been demonstrated on several occasions. See for example P. R. S. Kuruganty, R. Billington, P. R. Thompson and C. W. Wee, "Interconnection System Reliability Evaluation-Applications," Paper Presented to the Power System Planning and Operation Section of the Canadian Electrical Association (CEA), Spring Meeting, Toronto, March 1981.

[8] Canada, Department of Energy, Mines and Resources and United States, Department of Energy, p. 59.

[9] Costs of production comprise interest, depreciation, operation, maintenance and fueling charges plus a return on investment. New Brunswick's exports from its Coleson Cove plant to Maine are financed in this way.

[10] See for example a speech by Richard A. Snelling, the Governor of Vermont: "Remarks to the Montreal District Chamber of Commerce," February 11, 1981.

[11] In the case of exports from Canadian coal-fired facilities, this argument is based on the burning of western low-sulphur coal or, alternatively, eastern high-sulphur coal with 'scrubbers' to control sulphur emissions.

[12] If exports involve the construction of new facilities, debt-servicing payments could actually increase. See Note 6 above.

[13] Electrical World, "1982 Annual Statistical Report," March 1982, p. 82.

[14] Under U.S. regulatory procedures, utility profits are calculated on the 'rate base' which refers to the value of capital invested in generating plant and equipment. Utilities can include the cost of importing transmission lines, but not the cost of the imported power itself, in their rate base.

[15] Eric Hansen, "The Economic Impact of Inter-Utility Transactions on Manitoba Hydro's Generation Development," Paper Presented to the Conference on Environmentally Compatible Hydro Development, Canadian Water Resources Assocation - Ontario Region, Ottawa, May 1981, pp. 4 - 6.

[16] The Canadian facility could be a prebuild project (see above under 1.1.1, Capital Cost Savings) or an export-dedicated facility. The difference in export strategy is that under the prebuild the Canadian utility uses U.S. markets to optimize its internal system, while an export-dedicated plant involves building strictly for export (i.e., over the life of the plant). For ease of costing, the quantitative analysis in this study is constrained to export-dedicated facilities.

[17] This is not entirely unprecedented. For example, Manitoba Hydro has a diversity agreement with Northern States Power Company which has allowed it to defer the in-service date of the Limestone hydro project.

Chapter 2

ELECTRICITY EXPORTS IN PERSPECTIVE

This chapter provides some brief background to Canadian electricity exports to the United States, under two main headings: 1) historical perspective and existing levels, and 2) the institutional environment. Additional historical data is presented in Appendix B. Because of the dynamic nature of electric power exports, it should be noted that the information contained here is current to August 1982.

2.1 Historical Perspective and Existing Levels

Canada's history of electricity exports to the United States began around the turn of the century, with the construction of a 12-kilovolt transmission line at Niagara Falls. Since then, the interconnections between the two countries have grown to over 100 transmission lines, including 21 lines in excess of 100 MW capability.[1] Net Canadian electricity exports more than quadrupled in volume between 1975 and 1981, rising from 7 to 34 billion kilowatt-hours (see Figure 2.1). In terms of proportion of total net generation, this constitutes an increase of from 3 percent to 9 percent of total generation.

Early power exports were confined to sales of surplus energy from Canada's abundant hydroelectric resources. Most of these sales were made on a 'firm power' (see Glossary) basis, under long-term contracts designed to finance hydroelectric development in the province of Ontario. But as both domestic demand and source of supply changed, so too did the nature of Canadian power exports. Today, export sales take place from hydro, coal, oil and nuclear facilities. 'Interruptible' exports such as economy energy and emergency transactions now account for the majority of international trade in electricity. Figure 2.2 depicts total net power exports by province of origin, as well as interprovincial transfers, for 1981.

For several Canadian provinces, transmission capacity has been the limiting factor in electricity sales south of the border. At present, six provinces--New Brunswick, Quebec, Ontario, Manitoba, Saskatchewan (whose first interconnection went in service this year) and British Columbia--are interconnected with the United States (see Figures 2.3a and 2.3b). These interconnections yield a total transfer

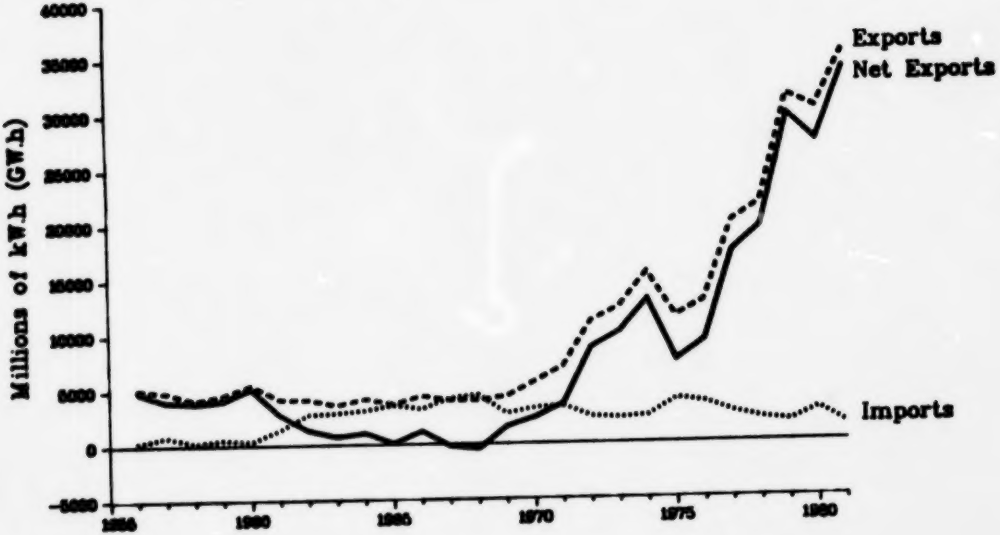
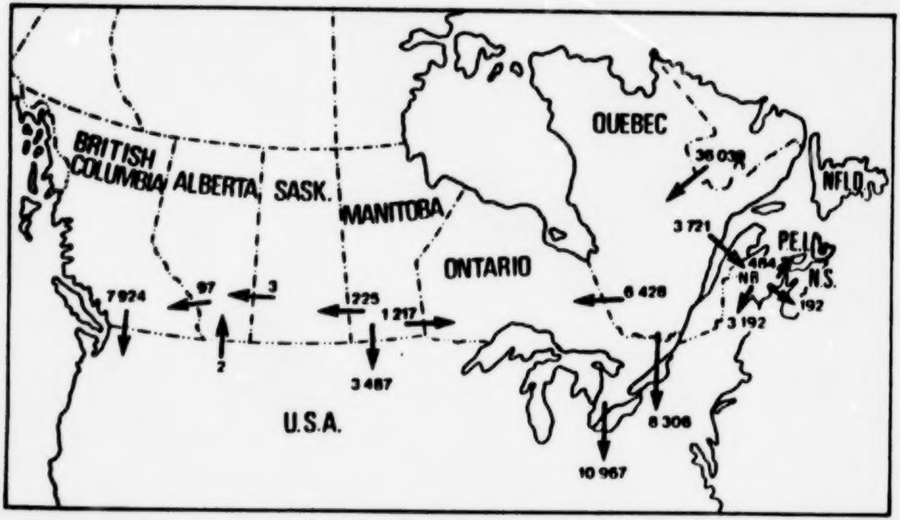


Figure 21: Canadian Electricity Trade 1956–1981
SOURCE:

Canada, Department of Energy, Mines and Resources, Electric Power in Canada: 1981 (Ottawa: Electrical Branch, 1982), Table 1.

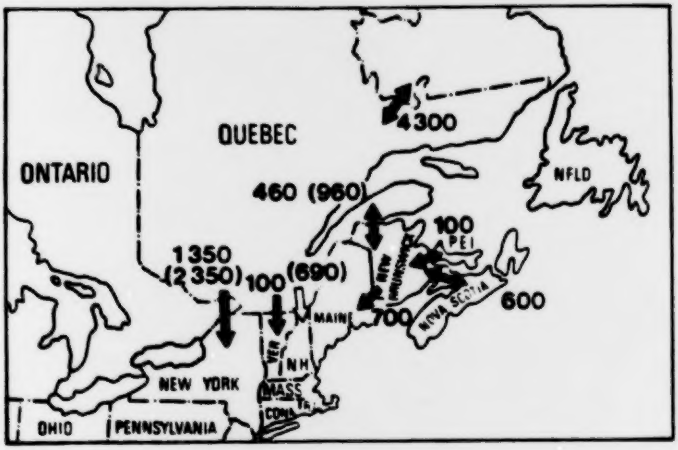
Canada, Statistics Canada, Electric Power Statistics, 57–001 Monthly and 57–202 Annual, Volume II, Table 17.


BRITISH COLUMBIA
ALBERTA
SASK.
MANITOBA
ONTARIO
QUEBEC
NFLD.
P.E.I.
N.S.
NB
U.S.A.
7 924
97
3
2
1 225
1 217
3 487
8 428
38 038
3 721
484
192
3 192
8 306
10 967

Source: Canada, Department of Energy, Mines and Resources, Electric Power in Canada 1981 (Ottawa: Electrical Branch, 1982), Figure 7.

Figure 2.2: Net Canadian Electricity Exports and Interprovincial Transfers - 1981 (GW.h)[a]

[a]Preliminary Figures


QUEBEC
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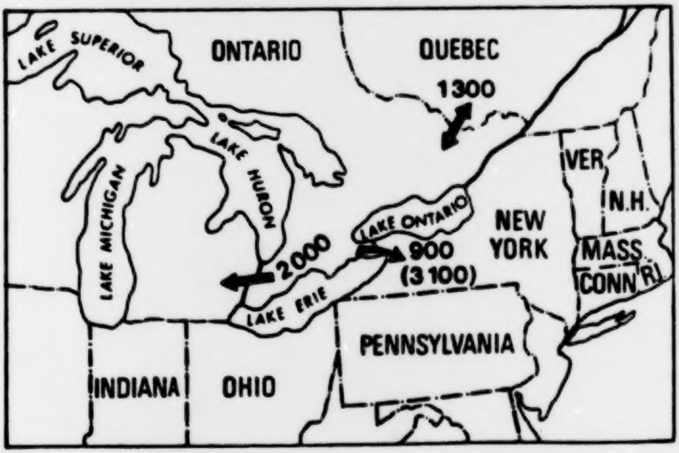
LAKE SUPERIOR
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2000
900
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LAKE ERIE
NEW YORK
VER
N.H.
MASS
CONN
RI
PENNSYLVANIA
INDIANA
OHIO

Sources: (For Figures 2.3a and 2.3b)
Canada, Department of Energy, Mines and Resources, Electrical Power in Canada 1979 (Ottawa: Electrical Branch, 1980), Electrical Power in Canada 1981 (Ottawa: Electrical Branch, 1982). Updated with information from utility sources.

Figure 2.3a: International and Interprovincial Transfer Capability (MW) - Existing and (Planned) Eastern Region

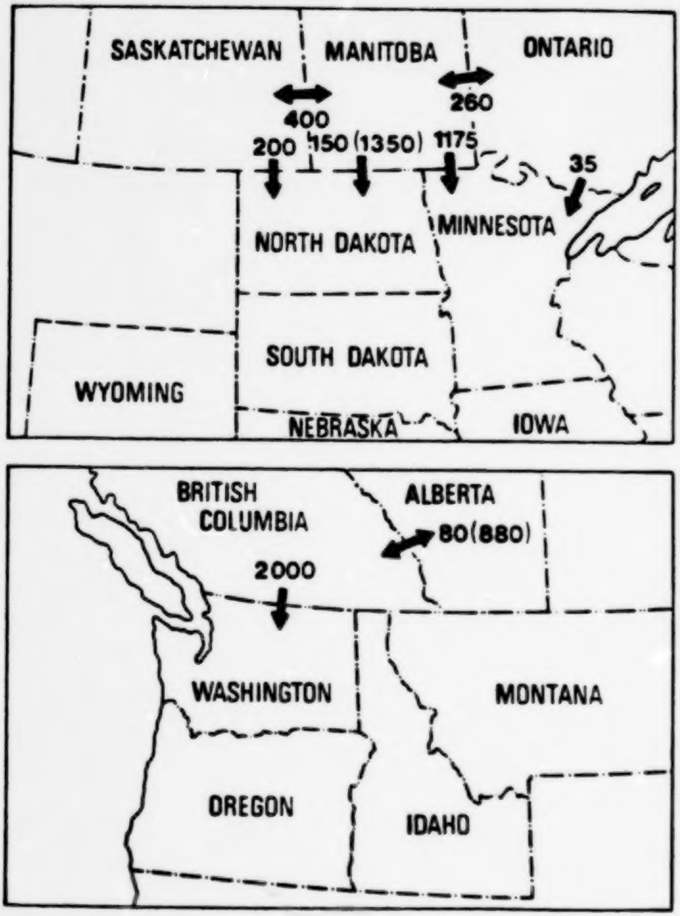
SASKATCHEWAN
MANITOBA
ONTARIO
400
260
200
150 (1350)
1175
35
NORTH DAKOTA
MINNESOTA
SOUTH DAKOTA
WYOMING
NEBRASKA
IOWA
BRITISH COLUMBIA
ALBERTA
80(880)
2000
WASHINGTON
MONTANA
OREGON
IDAHO

Figure 2.3b: International and Interprovincial Transfer Capability (MW) - Existing and (Planned)
Western Region[a]

[a]For international interconnections rated 69 kV and above.

capability of almost 9 000 MW. A number of planned transmission lines could add a further 5 100 MW to this capability by 1990.

2.2 The Institutional Environment

2.2.1 Organizational Structure

Canadian and American utilities differ quite extensively in their ownership composition and organizational structure. These differences, in turn, have implications for the regulatory and political environments in the two countries.

In Canada, the main electric utilities involved in generation are provincially-owned except in Prince Edward Island and Alberta. Two investor-owned utilities, TransAlta Utilities and Alberta Power, supply most of Alberta's power, with the Electric Utility Planning Council presiding over the coordination of generating and transmission facilities for all utilities. Over the years, public ownership of electric utilities has increased in Canada for the following reasons:[2]

- easier financing for facility construction, in the form of lower interest rates on government-backed utility bonds and access to major pools of financial capital in North America and Europe;
- certain efficiencies in the overall provincial supply of electricity through coordination of generating and transmission facilities; and
- a means of directing the electric power industry to reflect general public policy.

In contrast to the Canadian situation, most American electric utilities are investor-owned. The balance of generating capability falls to municipal systems, federal agencies and a number of large cooperatives.

The electrical industries in the two countries also differ on the basis of their internal interconnections. In the United States, utilities are organized into nine regions under a monitoring body called the North American Electric Reliability Council (NERC). Three of these regions include Canadian provinces; New Brunswick, Quebec and Ontario fall under the Northeast Power Coordinating Council (NPCC), Manitoba and Saskatchewan under the Mid-Continent Area Reliability Coordination Agreement (MARCA),[3] and Alberta and British Columbia under the Western Systems Coordinating Council (WSCC). Several of these regions are further divided into power pools. In addition, the Regional Electric Reliability Councils, as they are called, have formed major grid systems to facilitate interconnections. These grids correspond to the areas east and west of the Rocky Mountains, with Texas and Alaska being excluded for regulatory and geographical reasons, respectively.

Some Canadian provinces, particularly in the West, have been slow to establish ties with neighbouring provinces, largely because North America's population distribution has rendered north-south interconnections more economical. However, there has been growing interest in the notion of a Canadian grid to allow for the 'redistribution' of cheap surplus power within the country. In a 1978 report entitled An Evaluation of Strengthened Interprovincial Interconnections of Electric Power Systems,[4] the Interprovincial Advisory Council on Energy (IPACE) recommended the construction of high voltage interconnections between the provinces. These would be established in order to augment security of Canadian supply, and more specifically to realize the potential for reserve-sharing through time diversity exchanges and for fuel cost savings from more efficient use of hydro and nuclear resources. Indeed, there is evidence of a trend towards stronger ties between the provinces. A new transmission line is under construction between Alberta and British Columbia and negotiations are underway for strengthening of the New Brunswick-Quebec and Quebec-Ontario interconnections.[5]

2.2.2 Regulatory Environment

Both Canadian and American electric utilities are subject to considerable government regulation at the federal, provincial and state levels. In the United States, the federal government exerts the stronger influence, through its regulation of the interstate transmission of electricity and through its policies with respect to environmental impact. In Canada, although the federal government has a strong interest in such matters, most of the major electric utilities are either provincially or publicly-owned and the regulatory framework within which the utilities function is largely determined by the provinces. Both countries, however, assign the regulation of international electricity trade to their respective federal governments.

Canadian electricity exports must be approved by the National Energy Board, whose jurisdiction over electricity consists of regulating international power lines and issuing export licences. A public hearing is held to determine whether:

- the planned export is surplus to foreseeable provincial needs, as well as to the needs of other 'accessible markets', such as neighbouring provinces;
- the export price is just and reasonable to the extent that it covers the cost of generation in Canada, is not less than the cost of comparable service to provincial users and is not 'materially' less than the least cost alternative in the United States; and
- the environmental impact of the export is accounted for.

Licences may run for up to 25 years, although terms of 5 to 10 years tend to be the rule. Generally, licences are issued quite promptly, with the entire approval process (i.e., from application to licensing) averaging about one year.[6] This record has been due in part to the lack of overlap between federal and provincial jurisdiction over electricity exports. In some provinces (e.g., Quebec) provincial approval is required for export. In addition, the province has an influence through its environmental agencies and through its general involvement in system planning. Jurisdictional constraints may be even less of a factor in the future because of recent federal legislation.[7] This legislation will allow the National Energy Board to approve expropriation of rights of way for interprovincial and international transmission lines. The Board's new powers may help to settle the dispute between Newfoundland and Quebec over Newfoundland's request for a transmission corridor to export Lower Churchill power. They may also facilitate a more vigorous electricity export policy.

In the United States, electric utilities must obtain presidential permits for the construction, operation and maintenance of transmission facilities at the border. The issuing of permits has been delegated to the Economic Regulatory Administration (ERA) and the Federal Energy Regulatory Commission (FERC) of the Department of Energy. A public hearing may be held to examine environmental impact and other issues. Presidential permits do not specify a finite term, and may be terminated at the discretion of the ERA or FERC administrator.

Additionally, state public service commissions regulate the construction of transmission lines within state boundaries. Depending on the routing of transmission lines, other agencies which may enter the regulatory process include the Environmental Protection Agency, the Occupational Safety and Health Administration, the Security and Exchange Commission, the Department of the Interior and the Corps of Engineers.[8] But perhaps the most pressing problem related to multiple jurisdictions arises from the fact that a transmission line may have to cross several states. For example, the proposed Mandan transmission line between Manitoba and Nebraska has been stalled by court action in South Dakota, which lies to the north of Nebraska. In February of this year, the state utility commission refused to allow construction of the line through South Dakota territory on the basis that Nebraska could not provide sufficient evidence that it needed the summer surplus power.[9] An appeal is pending in the South Dakota courts.

Footnotes

[1] These and the figures which follow are taken from Appendix B.

[2] Canada, Department of Energy, Mines and Resources, Electric Power in Canada 1980 (Ottawa: Electrical Branch, 1981), p. 18.

[3] This region was recently renamed MAPP, the Mid-Continent Area Power Pool. However, it will be referred to as MARCA throughout this report.

[4] IPACE Networks Study Group, Report to Interprovincial Advisory Council on Energy, October, 1978.

[5] These proposed interprovincial ties exclude the Western Grid which was to have linked Manitoba, Saskatchwan and Alberta. Officially 'postponed' as of July 1982, this grid would have involved a 1700-kilometre transmission line to carry 1500 MW of hydro power from Manitoba to Saskatoon and Calgary.

[6] Canada, Department of Energy, Mines and Resources and United States, Department of Energy, p. 99.

[7] The relevant legislation was Bill C-108, the third of eight energy bills split off from the Cabinet's omnibus energy legislation last March. These amendments to the National Energy Board Act received Royal Assent on July 7, 1982. They will take effect with a six month lag in order to allow for a private settlement of the Newfoundland-Quebec dispute (see below).

[8] "Regulations Increase Utility Costs and Construction Delays," Energy, Spring 1981, p. 30.

[9] Electrical Business (Toronto: Kerrwil) March 1982, p. 1.

Chapter 3

UNITED STATES DEMAND FOR CANADIAN ELECTRICITY EXPORTS*

A primary factor affecting the U.S. demand for Canadian electricity is the relationship between the delivered cost of Canadian supply and the cost of domestic U.S. generation. However, other factors--including reliability or risk of supply disruption considerations, third party or externality effects, and the existing sociopolitical climate--also figure significantly in the outlook for increased electricity exports. In this chapter, we concentrate on analyzing quantitatively the demands for electricity exports as determined strictly by economic criteria. Some discussion of the importance of reliability considerations is also presented. A number of other potential constraints on the demand for Canadian electricity are addressed elsewhere in the study (see Chapters 1, 6, 7 and Appendix A)

U.S. export markets can be grouped into three broad classes: displacement of new generation facilities, displacement of existing generation facilities, and seasonal exchange of electricity. The first type of market requires a firm sales agreement whereas the latter two types could occur on a firm or interruptible basis. These markets could be served from Canadian surplus capacity or from a Canadian facility built for the export market (i.e., an 'export-dedicated' plant). The interface between Canadian supply sources and U.S. generation sources displaced defines particular types of export sale.

In this study, we analyze four types of electricity exports--dedicated capacity, dedicated energy, interruptible energy and seasonal diversity interchange (see Chapter 1 for definitions). These categories do not constitute the only potential types of export sale. Rather, they represent the most promising avenues for expanded Canadian electricity exports. A possible exception is the case of firm sales from Canadian surplus facilities. This type of sale is presently in use but its market potential was not analyzed due to the difficulty in costing the capital component of Canadian supply cost (which is needed in the analysis of Chapter 4).

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*The analysis in this chapter and supporting Appendices C through F is based largely on work undertaken by Martin Baughman in the report, Southwest Energy Associates, Inc., "United States Demand for Canadian Electricity Exports," Austin, Texas, October 1981.

It should be recognized that, according to the definitions in Chapter 1, no dedicated capacity or dedicated energy exports currently take place from Canada to the United States. In fact, for several provinces present government policy prevents the construction of facilities for export purposes. Seasonal diversity interchange between Canadian and U.S. utilities has occurred but with few exceptions (e.g., Manitoba Hydro's deal with Northern States Power) these exchanges have not been specifically undertaken to displace new capacity in utility expansion plans. Interruptible energy sales form the bulk of present electricity sales to the United States. Because of the speculative nature of several of the demands postulated, we qualify these demands as being 'potential'.

In this chapter and the next, we present a quantitative regional assessment of the potential U.S. demand for Canadian electricity. This assessment involves investigating the potential size of the market, Canadian supply cost, U.S. opportunity cost of generation, and relevant reliability criteria. Here we concentrate on assessing the size of the U.S. market and U.S. reliability considerations. In the next chapter, we cost likely sources of Canadian supply and, by comparing those costs with the costs of alternative U.S. generation, determine if the economic criterion for an export sale is satisfied. Then, for sales which meet this criterion, we estimate the magnitude of potential net economic benefits which could accrue to Canadian exporting utilities.

Other regional analyses of the electricity export market have been conducted, but generally only on the basis of a qualitative assessment of market potential.[1] Even detailed studies done for a particular jurisdiction have not explicitly analyzed either the size of the market or the extent of potential economic benefits available to exporting utilities.[2] In sum, the following differences in focus and approach differentiate this analysis from previous assessments of the U.S. market for Canadian electricity exports.

- Previous analyses have concentrated on the U.S. market for surplus power (either firm or interruptible), whereas the present analysis also specifically takes into account the potential market for capacity and energy sales from Canadian export-dedicated facilities.

- We analyze quantitatively whether the economic criterion for a market is fulfilled, that is, whether Canadian electricity can be delivered at a cost less than that of U.S. domestic generation.

- This analysis uses a system planning simulation model to identify, on a monthly basis, the potential for displacing oil-fired generation in the United States. Given the wide seasonal variation in supply capability and demand pressures in the U.S. markets under discussion, this approach represents a substantial improvement over qualitative market assessments.

For each of the four export classes discussed below, we describe the factors which affect the size of the market, provide demand estimates where relevant, and summarize any uncertainties and sensitivity results. The discussion generally centers upons the time frame from now to the year 2000. However, to the extent that additional Canadian facilities would be needed to supply the estimated demands, increased electricity exports would not be possible until the 1990s because of the lead times associated with planning, regulatory approval, and construction.

U.S. demand is analyzed for the nine regions and subregions depicted in Figure 3.1. These correspond to:

- ECAR (East Central Area Reliability Coordination Agreement);

- MAAC (Mid-Atlantic Area Council);

- MAIN (Mid-America Interpool Network);

- MARCA (Mid-Continent Area Reliability Coordination Agreement);

- New York (a subregion of NPCC, Northeast Power Coordinating Council);

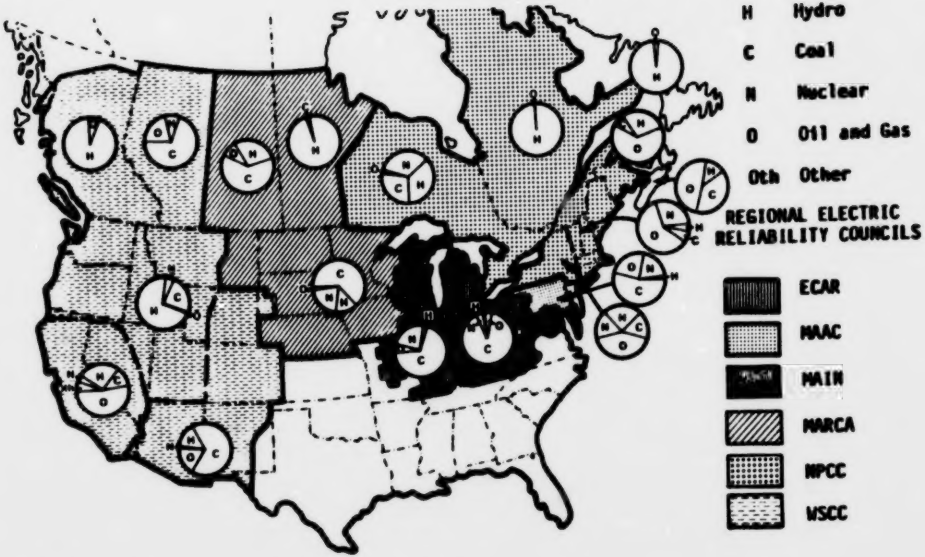
- New England (a subregion of NPCC);

- NWPP (Northwest Power Pool, a subregion of WSCC, Western Systems Coordinating Council);

- CANV (California-Nevada, a subregion of WSCC); and

- RMPA & AZNM (the Rocky Mountain Power Area and Arizona-New Mexico subregions of WSCC).

Excluded from the demand analysis are the southern regions of the United States represented by the Southeastern Electric Reliability


H Hydro
C Coal
N Nuclear
O Oil and Gas
Oth Other
REGIONAL ELECTRIC RELIABILITY COUNCILS
ECAR
MAAC
MAIN
MARCA
NPCC
WSCC

SOURCES: Canada, Department of Energy, Mines and Resources, *Electric Power in Canada 1980* (Ottawa: Electrical Branch, 1981).
North American (formerly National) Electric Reliability Council, "Electric Power Supply and Demand: 1981 - 1990" (Princeton: NERC, July 1981).

FIGURE 3.1: Generating Mixes in Canada and the United States - 1980 (kW.h generated)

Council (SERC), the Southwest Power Pool (SPP), and the Electric Reliability Council of Texas (ERCOT). These regions are sufficiently distant from Canadian sources that electricity could not be economically delivered to load centers on a routine basis.

Several considerations are important in understanding the ensuing analysis. First, the demand estimation uses as raw data input U.S. utility projections, by region, of electricity demand and installed generating capacity. These projections take account of scheduled imports and exports, so that the analysis starts from a base of planned exchanges. The potential markets identified above this base could be met by other U.S. utilities as well as by Canadian utilities. That is, competition for these markets could exist.

3.1 Potential U.S. Demand for Dedicated Capacity

3.1.1 Factors Influencing the Demand for Dedicated Capacity

A prominent factor influencing U.S. utility decisions to purchase capacity from generation facilities located in Canada is the economic consideration, that is, whether the power could be produced and transported to the United States at a cost less than it can be produced domestically. The relevant costs comprise the fixed and variable costs of generation in Canada and the cost of transmission to U.S. load centers, as compared to the counterpart capital and operating costs for new capacity in the United States.

However, other factors can complicate the economic equation. The first of these is reliability. Because electricity is not easily stored, an electric utility must possess sufficient generating capacity to meet any given level of demand on the system. If a deficiency of generation exists, the utility has no alternative but to curtail service in some way, either through requests for voluntary load curtailment or mandatory load reductions. A consideration of extreme importance if U.S. utilities are to purchase power from Canadian facilities is the perceived reliability of the service compared to that of self-owned and self-operated facilities. Even if a clear economic advantage can be demonstrated for the import of Canadian capacity, unless the terms of that delivery are considered inviolable a clear incentive exists for the U.S. utilities to build and operate their own capacity.

Secondly, in theory there exists a set of conflicting financial and ownership incentives. Electric utilities in the United States are all subject to price regulation by state regulatory commissions. Generally, a U.S. electric utility is allowed to recover its out of pocket costs of operation (including fuel, operation, maintenance, interest payments, and state and federal taxes), depreciation costs, and a fair return on equity capital. Since profits are a direct function of the amount of capital employed (i.e., the rate base), there exists an incentive for U.S. utilities to undertake capacity expansion themselves rather than to contract for Canadian capacity.

However, on practical grounds many utilities are delaying or avoiding additional capital expenditures. The costs of electricity supply have risen rapidly over the past several years as a result of fuel price increases, rapidly escalating costs of new plant and equipment, and rising costs of capital. Regulatory commissions have been reluctant, for political reasons, to grant increases in the allowed rate of return commensurate with increases in the cost of capital. Moreover, in many cases in which the allowed rates of return have been increased, utilities have earned returns below those allowed in regulatory proceedings because of sluggish growth in demand. Under these conditions, new plant and equipment must be financed from the sale of new stock, as opposed to earnings or depreciation reserves. This in turn 'dilutes' the equity of existing stockholders. In order to protect the assets of existing stockholders, some utilities are delaying or foregoing, as much as possible, capital expenditures on new plant and equipment.[3] Consequently there is some incentive for U.S. utilities to purchase external capacity rather than to build their own.

3.1.2 Demand Estimates

To illustrate the magnitude of the potential market for exports of dedicated capacity from Canada to the United States, we review the salient characteristics of three alternative electricity demand growth and capacity expansion scenarios for the nine U.S. regions under consideration (see Table 3.1). The low growth scenario incorporates a 2.0 percent average annual growth rate in electricity demand over the 1980 - 2000 period for the total of the nine regions considered. This growth rate is thought to be somewhat less than the soon-to-be released 1982 - 2000 demand growth projections reported by the North American Electric Reliability Council (NERC).[4] The mid growth scenario of 3.1 percent per year is consistent with the 1981 NERC projections, whereas the high growth scenario of 3.4 percent annually is essentially the 1980 NERC forecast.

TABLE 3.1

PROJECTED ELECTRICAL ENERGY CONSUMPTION GROWTH AND CAPACITY NEEDS IN POTENTIAL CANADIAN EXPORT MARKETS[a]

Region	Estimated 1980 Capacity (GW)	Low Growth			Mid Growth			High Growth		
		Annual Consumption Demand Growth (%)	Required Year 2000 Capacity (GW)	Capacity Net Increment Over 1990 (GW)	Annual Consumption Demand Growth (%)	Required Year 2000 Capacity (GW)	Capacity Net Increment Over 1990 (GW)	Annual Consumption Demand Growth (%)	Required Year 2000 Capacity (GW)	Capacity Net Increment Over 1990 (GW)
ECAR	93.7	2.2	128.0	20.4	3.3	164.7	42.4	3.4	182.7	54.7
MAAC	48.8	1.2	56.5	4.9	2.3	64.7	6.5	2.6	67.2	10.7
MAIN	45.7	2.4	63.2	7.2	3.5	82.4	22.6	3.9	91.4	28.2
MARCA	27.5	2.7	37.1	5.6	3.8	49.0	13.5	4.1	55.1	18.0
NPCC-New York	31.5	0.4	36.4	3.2	1.5	36.5	1.7	2.0	37.0	0.6
NPCC-New England	21.4	1.5	27.2	4.1	2.6	32.5	6.1	3.1	36.1	8.9
WSCC-NWPP	39.0	1.8	55.7	9.4	2.9	70.4	18.3	3.3	76.9	21.2
WSCC-CANV	40.4	1.8	61.5	8.1	2.9	78.8	20.5	3.3	87.2	25.7
WSCC-RMPA & AZNM	19.5	3.2	31.2	7.2	4.3	39.5	10.3	4.5	43.1	11.9
Total	367.5	2.0	496.8	70.1	3.1	618.5	141.9	3.4	676.7	179.9

SOURCE: Derived from tables in Appendix C.

[a] The increments are labelled 'net' increments because they exclude capacity that is added for replacement of retired capacity between 1980 and 2000. The growth rates for capacity are less than the corresponding growth rates for demand due to present excessive reserve margins.

The methodology employed in estimating the potential size of the market for dedicated capacity is to analyze U.S. utility expansion plans which would be consistent with the foregoing demand growth scenarios. For each U.S. region, the table shows the 1980 year-end installed capacity, the 2000 year-end capacity needed to meet demand under each growth scenario, and the net increment in capacity between 1990 and 2000. Attention is focused on capacity additions during the 1990 - 2000 time period because the majority of plants scheduled for completion before 1990 are already in various stages of construction.

These net additions become the potential size of the market for dedicated capacity. We realize that in some cases, however, these scheduled capacity additions are intended not only to meet forecast incremental demand but also to displace existing oil-fired generation. What the values in Table 3.1 reveal is that somewhere between 70 and 180 GW of net capacity additions would be required to satisfy electricity demands between 1990 and 2000, depending upon the growth assumptions. The region with the greatest number of capacity additions is ECAR (Michigan, Ohio, etc.).

As far as type of generating capacity is concerned, approximately 80 percent of the scheduled additions between 1980 and 2000 are either coal or nuclear plants (see Table D.1). Therefore, if Canadian dedicated capacity is to displace American capacity, it must be competitive with new coal and nuclear plants in the United States. A range of estimates of the costs of electricity from new U.S. coal and nuclear facilities is documented in Appendix D.

3.2 Potential U.S. Demand for Dedicated Energy

3.2.1 Factors Influencing the Demand for Dedicated Energy

The main reason for a U.S. utility to import dedicated energy is economic. The output of the Canadian export facility is purchased because the energy is less expensive than if it were to be produced from existing self-owned facilities. It is assumed that U.S. utilities possess enough capacity to meet reliably their own demands, but that some of the self-owned capacity is operated at reduced or zero load levels whenever lower cost energy is available from Canada.

Oil is the highest cost form of base load generation in the United States. As such, this generation type offers the greatest potential for displacement by Canadian electricity exports. Several prospective importing regions utilize oil-fired generation at high capacity factors. The export of additional electrical energy from Canada would most likely be produced by either hydroelectric, nuclear or coal facilities. The prospect that the full fixed plus variable costs of output from these facilities could compete with the marginal costs (i.e., operating costs alone) of oil-fired generation is not unreasonable, provided that the utilization of the exported capacities is high enough. As a result of these considerations, we highlight the potential for oil displacement at relatively high capacity factors.

3.2.2 The Analytical Approach

To facilitate the derivation of demand functions, a computer model of the U.S. electric utility industry was employed. This engineering economic simulation model, known as the Regionalized Electricity Model (REM), was calibrated to simulate the electric generation of the nine regional aggregates of interest in this study through the year 2000. A schematic diagram of the overall model structure and details concerning model inputs are provided in Appendix E.

Given inputs of peak demand and energy demand by region and by month, the model constructs a load duration curve.[5] It determines the least cost plant mix by 'stacking up' the available plant types, as needed, according to a generation cost hierarchy in which the lowest cost plant is added first and the highest cost plant last.

To measure the range of potential for electricity imports from Canada, different capacity blocks (of 200, 500, 1000 and 2000 MW) were assumed to be available to each U.S. consuming region for each of the study years 1985, 1990 and 2000.[6] The model was adapted to treat each capacity block as another plant type existing within the region. The price of energy available from each block of capacity was varied over a range of values determined by the marginal generation costs of different plant types. A simulation was then performed to determine the extent to which the imported capacity blocks would be relied upon to meet energy demands in each of the nine U.S. regions during the twelve-month period.

The resulting import demand functions are comprised of discrete blocks; that is, they take the form of step functions. There is no change in the import demand level as long as the cost does not fall below that of the plant type positioned below, nor rise above that of the plant type positioned above on the load duration curve.[7] For the case at hand, in which attention is directed towards displacing oil-fired generation, the relevant upper bound cost is the marginal cost of oil generation in the region, whereas the relevant lower bound cost is the marginal generation cost of the next lower cost generation type, namely coal.

In this manner, we estimate the total oil displacement market in the United States on a firm basis. We then identify this oil displacement market as the 'potential' size of the market for dedicated energy exports recognizing that it could also be served by firm sales from existing surplus capacity.[8]

3.2.3 Sensitivity Analysis

In order to account for sensitivity to capacity and load growth assumptions, results are presented for the following scenarios (as in Table 3.1):

- high growth scenario, i.e., high demand growth projection with corresponding capacity expansion;
- mid-growth scenario, i.e., medium demand growth projection with corresponding capacity expansion; and
- low growth scenario, i.e., low demand growth projection with corresponding capacity expansion.

In each of these scenarios, the rate of addition of new capacity in the U.S. consuming regions was adjusted to 'match' the load growth projection. These matched capacity scenarios were obtained by accelerating or delaying scheduled capacity additions from the mid growth expansion alternative by the amount of time required, or made possible, by the alternative assumptions on load growth (see Appendix C).

In addition to the above matched scenarios, the results of two cases for unmatched capacity and load growth are presented:

- over-capacity, i.e., low demand growth projection with the capacity projection corresponding to high demand growth; and
- under-capacity, i.e., high demand growth projection with the capacity projection corresponding to low demand growth.

In the analysis, alternative world oil price scenarios are also considered so that variation in the upper bound price of Canadian electricity exports can be illustrated.[9]

3.2.4 Demand Estimates

Attention is focused on the displacement of existing U.S. oil-fired generation at relatively high capacity factors. Export blocks of different sizes are assumed to be available to each region at a price between the marginal costs of coal-fired and oil-fired generation. The capacity or utilization factors at which these blocks are demanded have been calculated using REM, and the maximum size block (to a limit of 2000 MW) for which the capacity factor exceeds 50 percent has been identified. The 2000 MW block is thought to represent a reasonable limit for a dedicated energy sale between individual Canadian and U.S. utilities.

These upper bound capacity blocks are summarized in Table 3.2 for the three matched growth scenarios. The actual simulation runs (i.e., capacity factors) are presented in Appendix F. The regions which consistently demonstrate significant demands for electricity to displace oil are New England and California-Nevada. Under mid to high matched supply and demand growth assumptions, 9000 MW or more of Canadian capacity could be absorbed by U.S. utilities (at capacity factors of 50 percent or higher), if the delivered cost of the power were below the cost of displaced oil generation. Under the assumption of low demand growth and capacity expansion, this market reduces to about 4000 MW. Only under the 'unmatched' assumption of low demand growth and rapid capacity expansion, does the market evaporate entirely.

It should be noted that those regions which demonstrate a high capacity factor for the 2000 MW block could, in fact, absorb energy from still larger capacity blocks at relatively high capacity factors. The values indicate that under low to mid growth conditions 7000 to 26 000 MW of exported capacity could be absorbed at annual capacity factors of 50 percent or higher.[10] In particular, under the mid growth scenario New England, New York and MAAC could absorb 5000 MW each of oildisplacing capacity, whereas California-Nevada could absorb 10 000 MW (see Appendix F, Table 13).

3.3 Potential U.S. Demand for Interruptible Energy

Interruptible energy refers to short-term interruptible deliveries (from existing generation facilities over existing transmission lines) to effect fuel and other operating savings when the receiving party has adequate generation. Such agreements are usually entered into via verbal, rather than written, contracts between system

TABLE 3.2

Year 2000 CAPACITIES DEMANDED FOR DEDICATED ENERGY EXPORTS UNDER ALTERNATIVE MATCHED GROWTH SCENARIOS[a]

Importing U.S. Region	Matched Growth Scenario		
	Low (MW)	Mid (MW)	High (MW)
ECAR	-	-	-
MAAC	-	2 000	2 000
MAIN	-	-	-
MARCA[b]	-	1 000	2 000
NPCC-New York	-	2 000	2 000
NPCC-New England	2 000	2 000	2 000
WSCC-NWPP	-	-	500
WSCC-CANV	2 000	2 000	2 000
WSCC-RMPA & AZNM	200	500	2 000
TOTAL	4 200	9 500	12 500

SOURCE: Tables in Appendix F.

[a] To a limit of 2000 MW per region. The capacity factor at which capacity is demanded has been constrained to 50 percent or greater.

[b] The demands for MARCA represent displacement of existing higher cost (i.e., not just oil) capacity for intermediate load to peaking purposes.

operators. The terms of delivery are such that the agreements offer virtually no impact on system security and reliability.

The factors which influence the amount of interruptible energy exported are highly variable and uncertain. These include the extent of the loads on prospective interchanging systems relative to the capacity operating, the respective marginal costs of production from operating units, and the status and ratings of the transmission system. The demand for interruptible energy is also a function of short-term supply deficiencies in the candidate receiving region as a result of below-average water levels or forced generator outages.

As for the economics of interruptible energy sales, they are clear-cut. It is to the advantage of a potential buyer and seller to enter into a sales agreement when the marginal generation cost of one party is less than the marginal generation cost of the other party. Considering the presently large market share that oil-fired generation (which is relatively low in capital cost and high in operating cost) still has in several U.S. regions, one would expect Canadian hydro, nuclear, and even coal-generated electricity (which is relatively high in capital cost but low in operating cost) to offer significant economic advantages to these regions. In addition, we recognize that for some U.S. regions (e.g., MARCA) potential exists for short-term displacement of existing coal-fired generation from Canadian hydro sources.

Historically, however, a primary impediment to expanded interruptible sales has been the lack of transmission capability.[11] Generally, the level of interruptible sales has been supply-side determined. That is, the U.S. oil-displacement market has been able to absorb whatever Canadian interruptible energy has been available, subject to the transmission loading constraint. Because of this characteristic of the market and because of the transaction-specific nature of interruptible exchanges, estimates of the size of the U.S. market were not undertaken in this study.

3.4 The Potential Demand for Seasonal Diversity Interchange

Seasonal diversity interchange takes advantage of capacity cost savings which are possible when two regions have different seasonal peak demands. Several U.S. regions bordering on Canada are summer peaking (New York, MAAC, MAIN, MARCA and California-Nevada), while all the Canadian provinces are winter peaking. The potential for such seasonal exchanges lies in the prospect that, for a specified reliability criterion, the composite load for two regions may require a lower level of installed capacity than required if the two regions operate independently. That is, in its system planning a utility could allow a capacity credit for part of the installed capacity of its diversity partner. In this section, we consider the capacity savings that might be obtained if Canadian and U.S. regions were to enter into diversity interchange agreements.

A major consideration is that of providing sufficient flexibility to schedule the maintenance that is required under integrated operation of the systems. Conceivably, for example, if two systems' load patterns were exactly out of phase, the composite load shape could be flat. In this event, sufficient capacity would have to be available not only to meet the peak demands but also to provide sufficient capability so that a portion of the capacity could be scheduled out for maintenance. Under integrated operation there would be fewer off-peak periods. Usually what this implies is that, for the same reliability criterion, the required percent margin of reserve for a composite system sharing reserves (as would be the case with seasonal diversity agreements) would be higher than the required reserve margin for each of the two systems individually.

3.4.1 Estimates of Potential Capacity Savings

The procedure for calculating the potential capacity savings from diversity interchange was straightforward. First, seasonal energy demands were identified. Then, using this load data, each Canadian province was matched with possible diversity interchange partners in the United States. For each region individually, and for the two regions combined, installed capacity requirements (including reserve margins) were calculated. The difference between the sum of the capacities required for the two regions operating independently and that amount required if the two systems were integrated into a composite load was then calculated and labeled 'capacity savings'.

These savings are predicated on the assumption that the same reserve margin applies for integrated operation as for independent operation. Because of maintenance scheduling considerations, we also investigate the case of a 5 percent higher reserve margin under integrated operation. The seasonal load data used in making these calculations are presented in Appendix G.

Table 2 in Appendix G summarizes the potential capacity savings from diversity interchange for the study year 1982, under the above two assumptions with respect to reserve requirements. In several cases, each Canadian or U.S. region is shown more than once to display the possible savings that could be obtained by sharing reserves with alternative partners. Roughly 8000 to 17 000 MW of capacity savings could theoretically be available in 1982 under extensive interconnection and reserve-sharing initiatives.[12]

It should be noted that capacity savings of this magnitude could not presently be realized, since capacity additions for the year 1982 are either already in place or nearing completion. Additionally, some 'optimal' pairings of Canadian and U.S. regions might not be reasonable due to geographic considerations. A further qualification is that most Canadian and U.S. utilities currently have excessive reserve margins. However, the analysis does provide a base upon which to speculate on future potential capacity savings. For example, under the low growth demand scenario for both Canadian and U.S. energy demand (2.0 percent average annual growth), and taking geography into account, one would expect the potential capacity savings for the year 2000 to range from 7 000 to 20 000 MW, depending on the reserve margin (Table 3.3).

Whether this market for diversity interchange can be effectively penetrated by Canadian utilities is, nonetheless, problematical. Several agreements involving the seasonal exchange of power already exist between Canadian and U.S. utilities, as well as between pairs of U.S. utility regions.[13] For example, utilities in MAIN are already scheduled to purchase summer capacity of between 50 and 60 MW from the Southwest Power Pool and of 260 MW from the Tennessee Valley Authority. For 1982, MARCA has contracted for (net) summer imports of 700 MW and winter exports of 340 MW. These exchanges are principally with Manitoba and Saskatchewan. Net imports from the Northwest Power Pool into California-Nevada during the summer have historically been in excess of 2500 MW. For its part, New York already imports 800 MW of summer surplus from Hydro-Quebec. The net effect of these existing agreements is to reduce appreciably the present market for diversity interchange. Approximately 4500 MW of the potential diversity savings shown in Table G.2 are already accounted for by reported agreements.[14] Still more may be absorbed by interruptible exchanges. Thus, the present potential for expanded diversity interchange between U.S. and Canadian utilities appears limited. In the longer term, this potential is greater.

3.4.2 Economic and Technical Feasibility Considerations

For additional capacity savings through seasonal diversity interchange to be possible, increased transmission capability would be

TABLE 3.3

POTENTIAL SEASONAL DIVERSITY CAPACITY SAVINGS
YEAR 2000

	MW Capacity Savings	
Paired Regions	20 Percent Reserve	25 Percent Reserve[a]
B.C./California	3 000	-
Manitoba/MARCA	2 000	-
Ontario/MAIN	6 000	2 000
Quebec/MAAC[b]	8 000	5 000
New Brunswick/New York	1 000	-
Total	20 000	7 000

SOURCE: Derived by applying the low demand growth scenario of 2.0 percent per year between 1982 and 2000 to the 1982 potential capacity savings in Appendix G, Table 2.

[a] Assumes 5 percentage point higher reserve under integrated operation.

[b] Quebec is not paired with MAIN due to geographic considerations, even though the two regions have large seasonal diversity in load.

required between the participating regions. The rating of such transmission would depend upon how the savings were shared between the paired participants. If the savings were split equally between the two regions, a transmission capability that could reliably transmit approximately one-half the capacity savings would be required. During the winter months energy would flow from the United States to Canada. In the summer, the flow would be in the opposite direction.

If the entire capacity savings were located in the United States, then transmission capability rated to carry the full capacity savings would have to be installed. Canadian utilities would install essentially the same capacity as required to meet their own loads without interchange, and during the summer season they would export energy from some of that capacity to the United States. A net export of energy would result, U.S. utilities would enjoy the capacity savings, and Canadian utilities could configure their generating mixes with more base load generation--presumably offering some efficiency gains over the winter months when that same capacity would be used to serve Canadian loads.

Besides the offset to savings from additional transmission, there could be changes in production costs for the participating utilities.[15] As indicated earlier, several U.S. regions are heavily dependent upon oil-fired generation. Since the incremental fuel cost alone for existing oil-fired units exceeds the average costs of new coal and nuclear facilities, these regions would lower total generation costs by displacing oil-fired capacity. At the same time, to the extent that interconnection delayed a transition to lower cost domestic generation, production costs in U.S. regions would increase. Similar effects could also be experienced by Canadian utilities. Therefore, the ultimate impact of diversity interchange on utility production costs can be complex.

Finally, seasonal diversity interchange would require greater collaboration on the part of U.S. and Canadian utilities in planning and operating their systems than under traditional types of export sale. This is because the scheduling of generation and maintenance would have to be closely coordinated. The international nature of the transaction may discourage such pooling, with the result that sharing arrangements may be impractical.

3.5 Summary of Economic Considerations

In this chapter, we have identified upper bounds on the U.S. regional demands for four types of Canadian electricity exports. The role of reliability considerations has also been discussed. As emphasized in Chapter 1, the four export classes are neither exhaustive nor mutually exclusive. Because of the overlap among the potential markets as we have defined them, estimated demands cannot be summed across sale types.

The economic criterion for an export market is satisfied if Canadian electricity can be delivered at a cost less than the cost of alternative generation in the U.S. region. In this section, we summarize the relevant cost components to be considered in determining the economic feasibility of Canadian electricity exports in Chapter 4.

Across the four classifications of export, the determinants of demand and supply differ. These economic variables are illustrated in Table 3.4. Essentially, one can view costs associated with new or dedicated facilities as being long-run costs and costs associated with existing facilities as being short-run costs. Long-run costs include both capital (or fixed) and operating (or variable) cost components. Short-run costs on the other hand, entail only the operating or marginal cost component.

The demand price for Canadian electricity exports is bounded from above by the cost of domestic U.S. generation. The export supply price is bounded from below by the cost of Canadian generation plus the cost of transmission. For each of the four export types, relevant cost components depend upon whether Canadian supply is generated from new or existing plants, whether energy from planned or existing U.S. plants is being displaced, and whether existing transmission capability is adequate to service the international power flows.

TABLE 3.4

SUMMARY OF DEMAND AND SUPPLY CONSIDERATIONS UNDERLYING CANADIAN ELECTRICITY EXPORTS TO THE UNITED STATES

Export Category	Canadian Generation Requirements	Transmission Capability Requirements	Type of U.S. Generation Displaced	Capacity Expansion Plans Affected in		Importance of Reliable Supply to	
				Canada	U.S.	Canada	U.S.
Dedicated Capacity	new	new	new coal/ nuclear	yes	yes	no	yes
Dedicated Energy	new	new	existing oil	yes	no	no	no
Interruptible Energy	existing	existing	existing oil/ coal[a]	no	no	no	no
Seasonal Diversity Interchange	existing	new	new coal/ nuclear	yes	yes	yes	yes

[a] Only the market for oil displacement is analyzed in this study.

Footnotes

[1] See for example Canada, Department of Energy, Mines and Resources and United States, Department of Energy, Canada/United States Electricity Exchanges (Ottawa: Energy, Mines and Resources Canada, May 1979) and Mark Perlgut, Electricity Across the Border: The U.S. - Canadian Experience (Montreal: C. D. Howe Research Institute, December 1979).

[2] See for example A. R. Tussing, S. A. Van Vactor and C. C. Barlow, "Potential Markets in the Pacific Northwest and California for Surplus Electricity from British Columbia" (Seattle: ARTA, November 1981).

[3] For a discussion of the financial difficulties facing U.S. utilities and of their new mandate to minimize capital expenditures see Peter Navarro, "The Soft, Hard or Smart Path: Charting the Electric Utility Industry's Future," Public Utilities Fortnightly, Vol. 107, June 18, 1981: 25 - 30.

[4] The projections are those reported by the electric power industry to the Economic Regulatory Administration of the United States Department of Energy and documented by the North American Electric Reliability Council (formerly the National Electric Reliability Council).

[5] The load duration curve traces the distribution of kW demand over the month.

[6] The year 1985 is included for illustrative purposes, with the qualification that export-dedicated Canadian facilities are not considered possible until the 1990s.

[7] This constitutes a simplification. In reality one would expect the demand curve to be more smooth.

[8] It is assumed that both average and incremental supply costs range between the lower and upper bounds determined by marginal coal-fired and oil-fired generation, respectively (over the relevant range of 50 percent capacity factor or higher).

[9] The base case fuel price scenario involves a 2 percent real increase in world oil prices, whereas the low fuel price scenario entails a 0 percent real increase. These should be viewed as long-term oil price projections.

[10] Simulation experiments were not conducted under low growth conditions for potential capcity blocks greater than 2000 MW. Nevertheless, based on data trends in Appendices C and F, we view the New England and California-Nevada oil displacement markets to be in excess of 2000 MW and 5000 MW, respectively, for the year 2000.

[11] For example, in British Columbia transmission loading constraints mitigate against increased interruptible sales to the western United States. See Canada, Department of Energy, Mines and Resources and United States, Department of Energy, p. 8.

[12] The capacity savings cited do not refer to an 'optimal' match of Canadian and U.S. regions. That is, regions are not paired so as to provide the maximum capacity savings possible.

[13] These agreements are documented for each of the nine U.S. reliability councils in the Regional Reliability Reports to the Economic Regulatory Administration of the United States Department of Energy, under the title "Coordinated Bulk Power Supply Program 1979-1989," April 1, 1980.

[14] Again, it is important to note that existing seasonal diversity agreements are generally based on the exchange of surplus power in the participating systems and do not comprise the seasonal diversity interchange defined in this study, since they are not designed to displace the installation of new domestic capacity.

[15] Similar operating benefits would accrue under interruptible energy exchanges. Therefore, these operating economies are addressed in Section 3.3.

Chapter 4

INCREASED ELECTRICITY EXPORTS: THE CANADIAN SUPPLY RESPONSE

Chapter 3 examined the regional U.S. demand for several types of Canadian electricity exports. In Chapter 4, we investigate the potential supply response by provincial electric utilities to these capacity and energy requirements. The chapter begins with a general discussion of the export potential in each of the nine provinces under consideration (as of August 1982).[1] It then proceeds with a quantitative analysis of the net economic benefits from the four types of export sale defined in Chapter 1.

For the first three types--dedicated capacity, dedicated energy and interruptible energy--we calculate delivered costs from selected Canadian generating facilities to promising American markets. By comparing these delivered costs to the costs of alternative U.S. generation (i.e., U.S. replacement costs), the economic feasibility of export is ascertained. For those sales which satisfy the economic criterion, the potential net revenues to exporting utilities are then computed under certain pricing assumptions.

In the case of seasonal diversity interchange, we estimate the net capacity savings available between selected winter peaking Canadian utilities and summer peaking U.S. utilities. Potential net capacity savings consist of the cost of generating capacity avoided as a result of the seasonal exchange, less the cost of transmission required to interconnect the participating regions.

4.1 Provincial Potential for Increased Electricity Exports

4.1.1 The Atlantic Provinces

In the next decade, the oil-dependent northeastern states will provide attractive markets for surplus energy from several Atlantic power projects. Newfoundland has recently been pressing for a transmission corridor to export power from the yet-to-be developed Lower Churchill River Basin in Labrador. Indications are that surplus energy could be available from the proposed Gull Island site (1700 MW) sometime in the early 1990s.[2]

Nova Scotia is planning new coal-fired capacity for the 1980s and has just received a task force report[3] indicating the feasibility of Fundy tidal power. A station in the order of 4900 MW, as is proposed, would require an expanded market--including perhaps Quebec, New England, and New York--to absorb off-peak tidal energy.

Under a 10-year contract with the Maine Electric Power Company, New Brunswick will continue to export 133 MW of unit power from its Coleson Cove oil-fired plant. In addition, the New Brunswick Electric Power Commission has signed long-term contracts with several New England utilities to 'dedicate' 205 MW[4] of nuclear capacity from its 630 MW Point Lepreau station. It is possible that an additional unit could be operational at this station by the late 1980s, if New England markets can be defined and the federal government agrees to provide the appropriate financial guarantees. This unit would be a 'prebuild' since NB Power does not forecast further capacity requirements on its own system until the mid-1990s.

4.1.2 Quebec

In recent years, Quebec has been selling surplus hydro energy to New York state and Vermont. A limiting factor in Hydro-Quebec's interconnections has been that it is unable to operate its system synchronously with neighbouring systems, due to the remoteness of its generating facilities. As a consequence, the utility has found it necessary to disconnect specific generators in order to export energy to the Power Authority of the State of New York (PASNY).[5] The alternative to disconnecting generators is an asynchronous Direct Current (DC) link of the kind between Quebec and New Brunswick. Indeed, Hydro-Quebec is planning a new DC intertie with the New England Power Pool for the 1980s (see Appendix B, Table 2). Because of the diversity between Quebec's winter peak load and New York City's summer peak load, there is potential for increased sales of summer surplus power, as well as of surplus energy available during heavy water periods. Hydro-Quebec recently signed a contract with PASNY to deliver up to 111 000 GW.h of electricity between 1984 and 1997.[6] Furthermore, the utility is considering proposals from authorities in New England and New York that would see it accelerate hydro development to meet U.S. power needs in the 1990s. According to Hvdro-Quebec Chairman Joseph Bourbeau, it is possible that PASNY will finance the Grande Baleine/Great Whale complex (2900 MW) near James Bay, in return for long-term guarantees of electricity.[7]

4.1.3 Ontario

Most of Ontario's power exports to New York and Michigan have been short-term transactions for emergencies and for the displacement of higher cost generation ('economy sales'). Sales have originated mainly from the province's surplus coal-fired generation which uses imported U.S. coal. As in the case of Quebec, potential exists for seasonal diversity exchanges with summer peaking utilities in New York and the mid-Atlantic states. Any substantial increase in power exports would probably require reinforcement of Ontario's internal transmission network, as domestic loads increase through the 1980s.[8] With regard to interconnections, Ontario Hydro plans to upgrade its Niagara interties between 1981 and 1983 and experienced cancellation of its proposed Lake Erie submarine cable.[9] In addition to firm exports from surplus coal-fired capacity, there is growing interest in the concept of building nuclear plants for export. In 1972, a U.S. consulting firm presented a brief to the Ontario government on the feasibility of a 3000 MW nuclear station near Sault Ste. Marie, to be financed through long-term exports to Michigan, Illinois, Indiana and Ohio.[10] Since then, the Ontario government and more recently, the federal government have given serious consideration to export-dedicated or prebuild nuclear units, as possible means for helping to bridge the gap between current CANDU orders and domestic power needs by the year 2000.

4.1.4 The Prairie Provinces

Of the three prairie provinces, only Manitoba has a history of interconnections with the United States. Since the 1970s, Manitoba Hydro has been selling surplus hydro power to thermal-based utilities in MARCA (the Dakotas, Minnesota, etc). The opportunity for seasonal diversity interchange has been minimal as a result of the fact that neighbouring American utilities experience similar winter peaking loads. However, Manitoba Hydro has obtained a licence to exchange 300 MW of seasonal diversity power with Northern States Power Company, and has proposed the MANDAN transmission line to link with summer peaking utilities in Nebraska.[11] Given the province's considerable undeveloped hydroelectric resources, there is also potential for accelerating hydro projects to serve U.S. markets. Such a strategy would require firm power sales of the kind that were negotiated with Saskatchewan and Alberta for the proposed Western Grid.[12]

Saskatchewan recently completed its first international interconnection, a 230-kilovolt link between the province's Boundary Dam coal-fired station and Tioga, North Dakota. Until 1985, this line will be used for the exchange of 100 MW of seasonal diversity power with Basin Electric Power Cooperative of North Dakota. The Saskatchewan Power Corporation is a coal-based utility, and consequently its export opportunities vis-a-vis the predominantly thermal MARCA region lie mainly in such seasonal exchanges of power.

At present, Alberta has no plans to establish interconnections with the United States. Exports of surplus generation from the province's thermal coal resources could eventually be channelled to the U.S. Pacific Northwest through British Columbia, by means of a 500-kV tie due in service in 1985. Surplus energy of about 2000 GW.h could be available on an annual basis between 1984 and 1990.[13] Aside from surplus energy sales, the province could pursue a policy of prebuilding hydro or coal-fired facilities for export to U.S. markets.[14] This was the rationale behind a recent joint proposal by Fording Coal Limited, TransAlta Utilities and Alberta Power to develop an open pit coal mine and 2000 MW generating station northeast of Red Deer. With a projected inservice date of 1991, the Heatburg plant would initally have generated electricity for the northwestern United States. The proposal was rejected due to its impacts on local agriculture and water supplies.

4.1.5 British Columbia

British Columbia's exports to the Pacific Northwest have primarily taken the form of interruptible energy sales from surplus hydro generation. But perhaps the most promising external market for the provincial utility, B.C. Hydro, is the California-Nevada subregion (WSCC-CANV), where substantial oil-fired generation will likely continue in the wake of public opposition to nuclear power. One constraint on the export of power to this area is the loading of transmission lines between the Pacific Northwest and the Southwest. Transmission reinforcement within the western states could increase the potential for seasonal diversity exchanges with summer peaking utilities in Calfornia and Nevada. In common with several other provinces, British Columbia has significant hydro and coal resources in excess of anticipated domestic needs; hence there could be firm export opportunities through the advancement of northern river and coal-fired generation projects. Currently, however, B.C. Hydro has no mandate to build for export, and any change in the utility's export policy would require a political decision on the part of the provincial government. In any event, traditional exports of surplus hydro energy will probably continue, if not increase, in the future. The utility formulates its generation expansion plan to meet projected domestic loads under 'critical' or minimum water conditions. Therefore, surplus hydro generation will be available during periods of average or above-average streamflow conditions, and this surplus or margin will tend to increase with time as hydro projects are added.

4.2 Methodology for Calculating the Potential Net Revenues From Dedicated and Interruptible Exports

The 'potential net revenue' associated with an electricity export sale is defined to be the difference between the maximum price the export could command in the U.S. region and its delivered cost (i.e., generation cost plus transmission cost). This maximum price is tied to the cost of alternative, self-owned generation in the purchasing region. Potential net revenues are calculated for dedicated capacity, dedicated energy, and interruptible energy sales. It is assumed that 1000 MW (delivered)[15] of capacity is available for dedicated exports while interruptible energy sales are based on an assumed energy quantity of 5000 GW.h.[16] These uniform volumes of export are adopted for purposes of comparison. In fact, feasible export quantities will differ across provinces, years and types of sale (see below under section 4.5).

4.2.1 The Delivered Cost of Canadian Electricity

The delivered cost of an electricity export includes components for generation at the Canadian facility and transmission from the facility to the U.S. region. All calculations are derived from utility cost data. As such, they include only those 'external costs' (e.g., environmental costs) which are effectively 'internalized' by the utility through adherence to government regulations.[17] Furthermore, variable inputs (labour, materials, fuel, etc.) into the electricity production process are valued at their direct accounting cost to the utility, as opposed to their 'social opportunity cost' or their value to society in alternative uses.[18] Consequently, our calculations of delivered cost--and, by extension, potential net revenues--reflect a utility perspective and do not necessarily constitute costs, and net revenues, to society as a whole.[19]

Delivered cost is expressed in terms of mills[20] per kW.h of electric energy. It consists of the incremental operating (operation, maintenance and fuel) cost of generation and transmission facilities. In the case of dedicated exports, the capital costs of generation and transmission are also added in. All capital costs are amortized and divided by energy to arrive at a 'unit energy cost for capital amortization'.[21]

Generation Cost

For all three export types, delivered cost is based on a specific generation site in Canada. In fact, this approach is strictly relevant only to dedicated exports, the case in which particular facilities would be constructed for export. Interruptible sales, on the other hand, are in practice usually made from surplus energy at the grid, and may originate from several different facilities and types of generation. But, in the interest of costing transmission consistently across the three types of export sale, specific sites are used.

Table 4.1 lists by export type and study year the hypothetical sources of generation for each prospective exporting province. The particular facilities corresponding to these generating types are documented in Appendix H, as are the various assumptions used in calculating delivered cost (e.g., cost components, discount rates, capacity factors, escalation rates). Given the lead times involved in planning and construction, exports from Canadian dedicated facilities are not considered technically feasible until the 1990s. Dedicated capacity exports focus on the year 2000 because they are based on the regional increments to U.S. coal-fired and nuclear capacity between 1990 and 2000 (See Appendix C, Table 7). Interruptible energy sales are examined only for those provinces with existing or committed international transmission ties.[22] While the 1990 and 2000 study years have been extended to interruptible exports, a representative year in the 1980s could also have been selected for each of the five provinces under consideration.

TABLE 4.1

ASSUMED SOURCES OF GENERATION FOR CANADIAN ELECTRICITY EXPORTS

	Export Type/Study Year			
Province	Dedicated Capacity 2000	Dedicated Energy 1990, 2000	Interruptible Energy 1990	2000
Newfoundland	Hydro	Hydro		
Nova Scotia	Coal	Coal		
New Brunswick	Nuclear	Nuclear	Coal	Nuclear
Quebec	Hydro	Hydro	Hydro	Hydro
Ontario	Nuclear	Nuclear	Coal	Nuclear
Manitoba	Hydro	Hydro	Hydro	Hydro
Saskatchewan	Coal	Coal		
Alberta	Coal	Coal		
British Columbia	Hydro	Hydro	Hydro	Hydro

Transmission

Included in the delivered cost of Canadian electricity is a charge for transmission from the generating facility to one major load centre in the receiving U.S. region. Transmission cost in the case of dedicated exports incorporates a 'representative' capital cost estimate for new bulk transmission over the entire distance involved. (Interruptible energy sales, in contrast, take place over existing interconnections and do not include a capital cost component.) In view of the range of transmission distances under study (i.e., up to 3400 kilometres), our capital cost estimates are based on the use of High Voltage Direct Current (HVDC) transmission equipment. An HVDC link offers the ability to carry power from remote generating stations without intermediate switching stations as may be required for an AC system.[23] Appendix J contains the detailed cost data on transmission, as well as a listing of the transmission distances from Canadian generation sites to U.S. load centres.

4.2.2 U.S. Replacement Cost

U.S. replacement cost, or the cost of self-owned and operated generation in the U.S. region, is used in determining a delivered demand price for Canadian electricity. For dedicated capacity, the appropriate replacement cost is the average total (i.e., capital and operating) cost of a new coal or nuclear base load facility. For dedicated energy and interruptible energy, only the marginal cost (i.e., operating cost) of existing oil-fired generation is relevant. Replacement costs by region and export type are presented in Appendix I. The various costing assumptions are consistent with those adopted for Canadian delivered cost.

4.2.3 Delivered Demand Price

In determining a pricing rule for interruptible energy, we refer to historical experience. Most Canadian utilities have priced interruptible exports according to the split savings rule, that is, mid-way between the incremental cost of the export and U.S. decremental cost.[24] In the case of dedicated exports on the other hand, there is no true precedent for pricing an electricity sale.[25] The general National Energy Board pricing rule stipulates that export price should recover an appropriate share of the cost incurred in Canada, that it should not be less than the price for equivalent service to Canadian customers, and that it should not be materially less than the price of the least cost alternative in the importing region.

In our analysis, we arbitrarily value both dedicated capacity and dedicated energy at the full U.S. replacement cost. In practice, reliability considerations could lead to a price below this maximum, particularly in view of our assumption that U.S. utilities would bear the responsibility for backup generation. Furthermore, a prospective importer would require some degree of cost saving to induce him to substitute foreign for domestic generation. Nevertheless, our purpose here is to demonstrate the maximum 'potential' net revenues available to Canadian exporters. To the extent that final negotiated price was to fall below the upper bound demand price, a portion of the surplus from a dedicated export would be appropriated by the importing utility and its customers.

4.2.4 Identification of Potential U.S. Markets

Appendix I contains the calculations of potential net revenues for alternative study years, oil price and demand growth scenarios, and discount rates. Each Canadian province is arbitrarily assigned a single U.S. market across the three classes of export sale. It is important to note that this assignment of markets is strictly illustrative and is not intended to provide an optimal export strategy either from an individual utility or national perspective. With the exceptions of Manitoba and Saskatchewan, provinces are assigned to markets which are expected to rely heavily on existing oil-fired units for their base load generation. These promising oil displacement markets correspond to: NPCC-New England for Newfoundland, Nova Scotia and New Brunswick; NPCC-New York for Quebec and Ontario; and California-Nevada (WSCC-CANV) for Alberta and British Columbia. Because of the transmission distances involved in exporting to more attractive markets, Manitoba and Saskatchewan are matched with their closest market region, MARCA, where oil-fired generation is less predominant as a result of local lignite coal deposits.

In Table 4.2, the types of displaced generation and the associated capacity factors[26] are presented for each U.S. region under consideration. In the case of dedicated capacity sales, the displaced generation is assumed to be coal-fired units for New England, New York and MARCA, and nuclear units for California-Nevada. In fact, under the mid growth scenario for U.S. capacity and demand, the majority of capacity additions between 1990 and 2000 are coal-fired for all four of these markets. But a typical nuclear facility is used for WSCC-CANV in view of recent licensing delays on nuclear plants in California and in view of the general public and political opposition to nuclear power in that state. Coal displacement is particularly relevant for the northeastern states, on the other hand, since firm exports from Canada have been suggested as a means of reducing U.S.-produced acid rain in the eastern provinces.

TABLE 4.2

TYPES OF U.S. GENERATION DISPLACED (AND CAPACITY FACTORS) FOR 1000 MW DISPLACEMENT--MID GROWTH SCENARIO

U.S. Region	Export Type/Study Year			
	Dedicated Capacity 2000	Dedicated Energy 1990	Dedicated Energy 2000	Interruptible Energy[a] 1990, 2000
NPCC - New England	Coal (70%)	Oil (86%)	Oil (76%)	Oil
NPCC - New York	Coal (70%)	Oil (55%)	Oil (77%)	Oil
MARCA	Coal (70%)	Oil (20%)	Oil (50%)	Oil
WSCC - CANV	Nuclear (70%)	Oil (96%)	Oil (89%)	Oil

[a] Capacity factors not appropriate because based on a 5,000 GW.h energy sale.

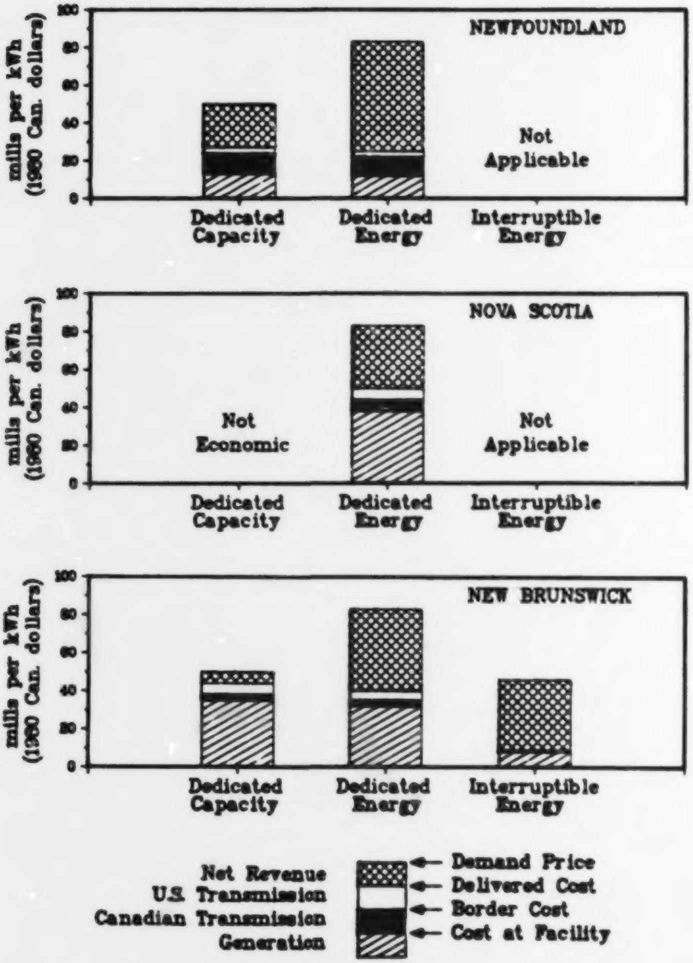
4.3 Results for the Potential Net Revenues from Dedicated and Interruptible Exports

For illustrative purposes, we focus on the study year 2000 which is common to all three classes of export sale. Figures 4.1 through 4.4 depict the potential unit net revenues to provincial utilities from supplying electricity to selected U.S. markets. Results are shown for the 'base case' scenario--a 7 percent real discount rate and 2 percent annual real growth in world oil prices. For each prospective sale, transmission cost is broken down into components for transmission within Canada (i.e., from the generation site to the international border) and transmission within the United States (i.e., from the border to the U.S. load centre) to yield both a border cost and a delivered cost at the U.S. region. Again, interruptible energy sales are considered only for those provinces which have a history of interconnections.

Strictly speaking, it is difficult to compare potential unit net revenues across the three types of export because of our different pricing assumptions for dedicated and interruptible sales. But despite this limitation, Figures 4.1 through 4.4 do convey an indication of the relative magnitudes involved, and of the substantial net revenues available from the displacement of U.S. oil-fired generation.

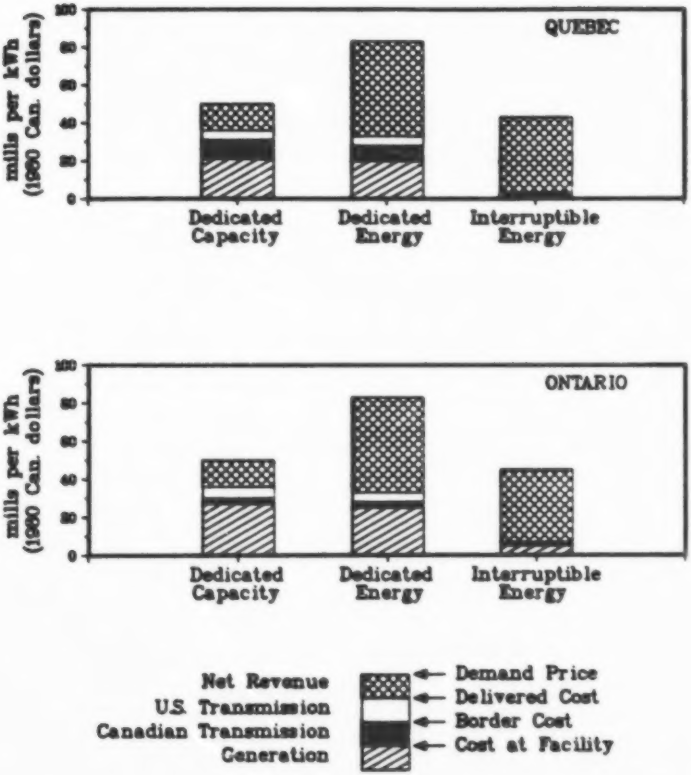
These potential net revenues are considerable for dedicated energy sales across all prospective exporters and generation types. Even Manitoba and Saskatchewan deomonstrate large surpluses, despite the fact that the calculations are based on only a 50 percent capacity factor for displacing oil in MARCA. In the cases of Alberta and British Columbia, the high cost of oil in California-Nevada more than compensates for the disproportionate cost of transmission to U.S. load centres.

For the five provinces studied, the potential unit net revenues from interruptible energy are comparable to those from dedicated energy sales, in spite of the more conservative pricing rule. This is a result of the magnitude of saving between Canadian incremental operating cost and the marginal cost of oil in the United States. In the study year 2000, interruptible energy sales are assumed to come from nuclear and run-of-the-river hydro facilities which exhibit low and minimal incremental costs, respectively, relative to coal-fired and oil-fired generating facilities.[27] However, even interruptible exports based on coal-fired generation (i.e., coal-fired exports from New Brunswick and Ontario for the 1990 study year) result in substantial



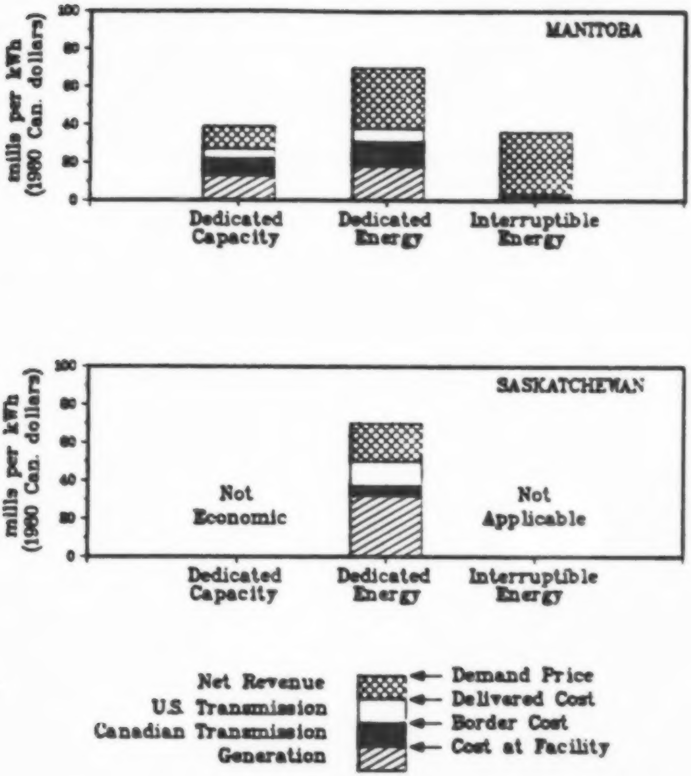
Source : Tables 3, 12 and 18 in Appendix I

Figure 4.1: Potential Costs and Net Revenues from Supplying NPCC – New England in the Year 2000 (Base Case)



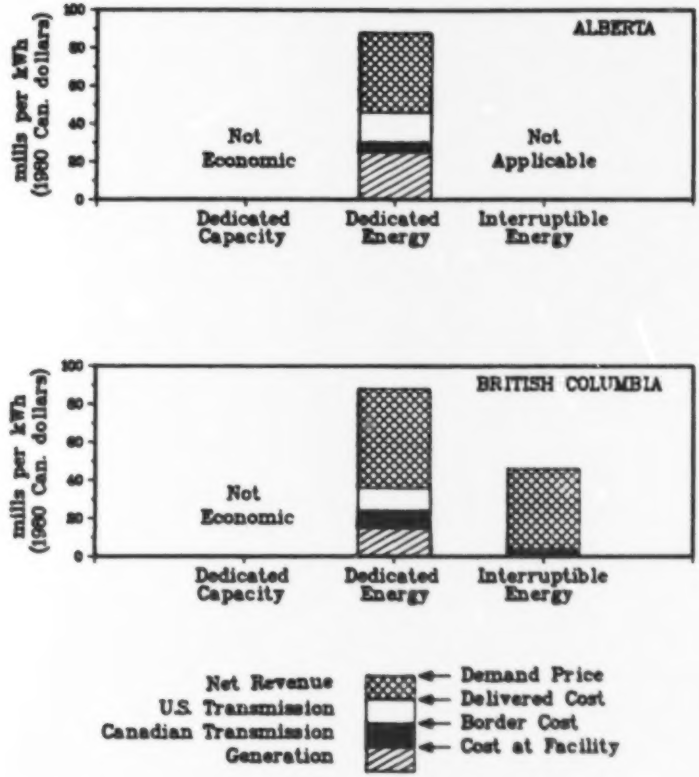
Source : Tables 3, 12 and 18 in Appendix I

Figure 4.2: Potential Costs and Net Revenues from Supplying NPCC - New York in the Year 2000 (Base Case)



Source : Tables 3, 12 and 18 in Appendix I

Figure 4.3: Potential Costs and Net Revenues from Supplying MARCA in the Year 2000 (Base Case)



Source: Tables 3, 12 and 18 in Appendix I

Figure 4.4: Potential Costs and Net Revenues from Supplying WSCC – CANV in the Year 2000 (Base Case)

surpluses under the split savings pricing formula (see Appendix I, Table 18).

When it comes to dedicated capacity exports, the potential net revenues are much smaller than those available in the market for oil displacement. This follows from the fact that Canadian capacity must compete with counterpart new capacity in the United States, the average total (i.e., capital plus operating) cost of which is approximately half the marginal cost of oil-fired generation. On the basis of new coal or nuclear displacement, dedicated capacity sales appear uneconomic for several prospective exporters. Alberta and British Columbia are unlikely to be capable of delivering capacity below the cost of a new nuclear facility in California because of the transmission expense to Los Angeles.[28] Of those provinces matched with more proximate U.S. regions, Nova Scotia and Saskatchewan show little promise since they must compete against similar coal-fired generation in their respective markets. The main potential for dedicated capacity sales seems to lie with hydro exports from Newfoundland, Quebec and Manitoba, and nuclear exports from Ontario.

4.4 The Potential Net Capacity Savings from Seasonal Diversity Interchange

Chapter 3 demonstrated the potential for capacity savings between winter peaking Canadian systems and summer peaking U.S. systems through participation in seasonal diversity interchange. Our purpose here is to estimate the value of these capacity savings less the cost of transmission required to interconnect reliably the participating regions. The estimates of net capacity savings in Table 4.3 are predicated on the split savings case in which energy sales from one-half of the total savings would be sent from Canada to the United States in the summer and then the same amount of energy would be returned to Canada in the winter. Specifically, 2000 MW of capacity savings are assumed to be divided equally between the participating regions, rendering a seasonal export of 1000 MW. Calculations are shown for those provinces which demonstrate capacity savings with U.S. regions under the 20 percent reserve criterion.[29] As in the analysis of dedicated and interruptible exports, we do not attempt an optimal matching of Canadian provinces and U.S. regions. Generating capacity savings are based on the particular facilities used for dedicated exports in the 2000 study year. Transmission capital cost refers to the cost of an HVDC link between the Canadian generation source and the U.S. region.[30] The difference between unit generating capacity savings

TABLE 4.3

POTENTIAL VALUE OF NET CAPACITY SAVINGS FROM DIVERSITY INTERCHANGE[a]
2000 STUDY YEAR
(1980 $/kW Canadian unless otherwise indicated)

Province/ U.S. Region	New Brunswick/ NPCC-New York	Quebec/ MAAC	Ontario/ MAIN	Manitoba/ MARCA	British Columbia/ WSCC-CANV
Unit Generating Capacity Savings[b]	2140	1770	1690	1040	1460
Unit Transmission Capital Cost[c]	350	490	250	460	820
Total Annual Potential Net Capacity Savings (1980 $MM)[d]	130	80	110	30	30

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[a] For 2000 MW of capacity split evenly between the Canadian and U.S. region.

[b] Capacity savings refer to the capital cost of a new nuclear facility in New Brunswick and Ontario, and a new hydro facility in Quebec, Manitoba and British Columbia, for the year 2000.

[c] To carry one-half of the total capacity savings (i.e., 1000 MW). This cost is split evenly between the Canadian and U.S. region.

[d] Capacity savings are amortized using a 7 percent real discount rate and the following plant lives:

Transmission	25
Coal	35
Nuclear	40
Hydro	70

and unit transmission capital cost gives potential unit net capacity savings. This figure multiplied by the quantity of capacity saved yields total potential net capacity savings in millions of dollars. These total net savings are then amortized so that they can be compared to the annual potential net revenues from dedicated and interruptible exports.

The calculations indicate capacity savings in the range of the potential net revenues from dedicated capacity exports. These savings could be significant for provinces planning to install hydro or nuclear capacity which is characterized by a high capital cost. It is important to note that we have not taken into account the possible changes in production costs from diversity interchange which were mentioned in Chapter 3. Presumably, in the short run, there could be substantial production cost savings, especially for U.S. utilities who would otherwise generate electricity from high cost oil. In the long term, both U.S. and Canadian production costs could be higher since the diversity purchase could delay the transition to lower cost sources of domestic generation.

4.5 Conclusions and Qualifications

The process of identifying promising U.S. markets for Canadian electricity has been specified to be a function of three basic criteria:

- the potential size of the market
- the potential direct net benefits to exporting utilities
- U.S. reliability considerations

The first and third issues were addressed in Chapter 3, while the potential net benefits to utilities have been the subject of this chapter. These net benefits have been expressed in terms of potential net revenues for the first three classes of export sale under consideration--dedicated capacity, dedicated energy and interruptible energy--and in terms of potential net capacity savings for the fourth export class, seasonal diversity interchange.

Table 4.4 summarizes the estimated net benefits to Canadian utilities for the study year 2000. The unit potential net revenues for dedicated and interruptible exports have been converted to total net revenues (in millions of dollars) by multiplying by the relevant amounts of energy. Although the four export classes are not strictly additive (i.e., there is market overlap), it can be inferred that annual net benefits in excess of two billion dollars (1980) could be

TABLE 4.4

SUMMARY OF POTENTIAL NET BENEFITS TO CANADIAN UTILITIES FROM INCREASED ELECTRICITY EXPORTS BASE CASE YEAR 2000[a]
($ 1980 millions Canadian)

U.S. Region/ Province	Capacity Displacement	Oil Displacement			Diversity Interchange	
	Dedicated	Dedicated		Interruptible	25% Reserve	20% Reserve
	Low or Mid[b]	Low	Mid	Low or Mid		
New England						
Newfoundland	140	480	390	N/A	N/A	N/A[c]
Nova Scotia	N/E[d]	220	220	N/A	N/A	N/A
New Brunswick	40	350	290	190	N/A	130[e]
New York						
Quebec	80	40[f]	340	200	80[g]	80
Ontario	90	50[f]	340	190	110[h]	110
MARCA						
Manitoba	70	100[f]	140	170	N/A	30
Saskatchewan	N/E	60[f]	90	N/A	N/A	N/A
California-Nevada						
Alberta	N/E	280	280	N/A	N/A	N/A
British Columbia	N/E	440	400	210	N/A	30
TOTAL	420	2020	2490	960	190	380

SOURCE: Tables I.3, I.12, I.16, I.18, and 4.3.

[a] For 1000 MW of dedicated exports and capacity savings from diversity interchange, and 5000 GW.h of interruptible energy. Assumes a 7 percent real disount rate and 2 percent annual real escalation in world oil prices.

[b] The low and mid U.S. growth scenarios correspond to 2.0 and 3.1 percent per year, respectively, for the 1980 - 2000 period.

[c] Not Applicable.

[d] Not Economic.

[e] New Brunswick matched with New York for diversity interchange.

[f] Market was not identified in Table 3.2 as 1000 MW block was demanded at a capacity factor less than 50 percent.

[g] Quebec matched with MAAC for diversity interchange.

[h] Ontario matched with MAIN for diversity interchange.

available to Canadian utilities in the long term from these types of export.[31]

The export classes can be ranked according to the three criteria mentioned above:

Potential Market Size	Potential Unit Net Benefits	Reliability
Dedicated Capacity	⎧Dedicated Energy	Interruptible Energy
Interruptible Energy	⎩Interruptible Energy	Dedicated Energy
⎧Dedicated Energy	⎧Dedicated Capacity	⎧Dedicated Capacity
⎩Diversity Interchange	⎩Diversity Interchange	⎩Diversity Interchange

On the face of it, the most attractive prospect for increased electricity exports would appear to rest with the market for oil displacement in the United States. Although the potential market for capacity displacement is large, the net revenues available on on individual sale (i.e., per kW.h) basis are much less than those from dedicated or interruptible energy. This is because Canadian electricity must be generated and delivered at a cost less than that of a new coal-fired or nuclear facility in the importing region. Under a replacement cost pricing rule, this results in smaller net revenues than in the case of high cost oil displacement. Furthermore, both dedicated capacity and seasonal diversity interchange would probably have to meet strict reliability criteria due to the fact that U.S. utilities would be foregoing the installation of domestic capacity.

Of the two types of oil-displacing sales considered here, each has its drawing points. The interruptible energy sales which have encompassed most of Canada's electricity exports in the past offer a convenient outlet for surplus generation available on a seasonal basis or during high water periods, as well as for energy from year-round excess capacity in provincial systems. At the same time, these sales are short-term and discretionary in nature and so do not involve a 'tying up' of Canadian generation resources. Dedicated energy, on the other hand, would be sold on a firm contract basis and may be regarded as a means of securing U.S. markets into an uncertain export future.

As a qualification to the above analysis, we emphasize that the export prices and volumes adopted in this chapter are strictly hypothetical. In particular, the pricing strategy for dedicated exports is the most favourable one to Canadian utilities, in the sense that electricity is priced at the full U.S. replacement cost with no allowance for reliability considerations or cost savings to purchasing utilities.

In the case of interruptible energy, actual export volumes would depend on a number of factors including time of year, water conditions and loading of transmission lines. With regard to dedicated exports, it is conceivable that larger utilities like Ontario Hydro, with its standard 850 MW nuclear unit size, would be willing to commit a larger capacity block than 1000 MW to the export market, while smaller utilities like the Nova Scotia Power Corporation would prefer to export smaller amounts of power. Of course, one constraint on the size of a prospective dedicated facility would be the financial capability of the utility whose role it was to provide financing. Presumably, these financial limitations would be greater for U.S.-financed projects, given the regulated rates of return currently being experienced by American utilities. However, there could be exceptions to this rule; for example, the proposal for U.S. financing of the Grande Baleine project in Quebec[2] is based on PASNY's access to nontaxable state bonds which provide it with a 5 to 6 percent financing advantage over Canadian utilities.[3]

Another qualification relates to transmission capability. We have already mentioned the transmission loading constraints on interruptible energy. But for dedicated exports, as well, it may not be realistic to assume that adequate transmission capacity could be installed to carry the loads posited here, and within a reasonable time frame.[33] Utilities in both countries have recently experienced major regulatory delays in the commissioning of new transmission. As an example, Ontario Hydro faced ten years of public hearings, court action and government inquiries before the first 500-kV line from its Bruce nuclear station was finally placed in service in June 1980.[34] In the United States, these delays are compounded by the problem of overlapping regulatory jurisdictions. Transmission will be further discussed in Chapter 6, along with a number of other potential constraints on increased electricity exports (U.S. competition, etc.).

In this chapter, we have focussed on the potential direct net benefits to Canadian utilities from increased electricity exports. In the next two chapters, some of the more indirect benefits and costs from export, including employment effects and environmental impacts, will be discussed.

Footnotes

[1] Prince Edward Island, the Northwest Territories and the Yukon have been excluded from the analysis because of geographical constraints. However, there is potential for the establishment of ties between Yukon and Alaskan power systems, and for the export of surplus hydro power from the Yukon River Basin to growing Alaskan markets. See Canada, Department of Energy, Mines and Resources and United States, Department of Energy, Canada/United States Electricity Exchanges (Ottawa: Energy, Mines and Resources Canada, May 1979), pp. 93-96.

[2] Actual timing of the Gull Island development depends on Newfoundland's ability to recall Churchill Falls power in its ongoing dispute with Hydro-Quebec (see Appendix A). If the province is successful in securing either a substantial block or all of the power from its 5225 MW plant, Gull Island may be considerably delayed. In this event, exports to the United States might be based on Churchill Falls energy not sold in province or exported to other provinces.

[3] The Task Force on Fundy Tidal Power was composed of representatives from Nova Scotia Tidal Power Corporation, Nova Scotia Power Corporation (the provincial electric utility) and federal and U.S. energy experts. Their report entitled Update '82 estimated that a 4864 MW plant between Economy Point and Cape Tenny would be competitive with nuclear power and more economic than coal and oil. It is anticipated that approximately 90 percent of the energy generated would be exported to northeastern U.S. markets.

[4] New Brunswick plans to export 335 MW of Lepreau power in total. At present, only the 205 MW for which NB Power has contracts has received National Energy Board approval.

[5] Quebec, Direction Generale de l'Energie, An Energy Policy for Quebec: Insurance for the Future (Quebec: Direction Generale de l'Energie, 1978), p. 50.

[6] Energy Analects (Don Mills, Ontario: Corpus Mills), April 9, 1982, p. 1.

[7] Ibid., pp. 1 - 2. The proposed capacity for Grande Baleine is taken from Hydro-Quebec, "A Strategy for the 80's" (Montreal: Hydro-Quebec, December 1980), p. 47.

[8] Arthur Porter, The Report of the (Ontario) Royal Commission on Electric Power Planning, Volume 2, "The Electric Power System in Ontario" (Toronto: RCEPP, February 1980), p. 63.

[9] Under a ten-year contract that was to have started in 1985, this cable would have allowed for the sale of 1000 MW of firm power to General Public Utilities of New Jersey, part-owner of the Three Mile Island nuclear plant. Last June, Hydro announced that GPU had

cancelled the deal because of rising project costs and financial and regulatory uncertainties.

[10] Acres Consulting Services Limited, Canadian Nuclear Power for Export, November, 1972.

[11] In February 1982, the MANDAN line suffered a setback when South Dakota refused to allow construction of that portion of the line which would have passed through its territory (see Chapter 2). An appeal has been filed in the South Dakota Appeal Court.

[12] Cancelled last July after four years of study and negotiations, the Western Grid would have seen the construction of Manitoba's Limestone generating station in order to carry firm power (500 MW and 1000 MW, respectively) to Saskatchewan and Alberta.

[13] A follow-up report to the Western Region's contribution to Canada/United States Electricity Exchanges (see Note 1) estimated surplus coal-fired energy available from Alberta, taking into account transmission constraints. 'Marketable surplus energy' was projected to be 1656 GW.h and 2575 GW.h for the 1984-85 and 1989-90 study years, respectively. See Alberta Interconnected System, British Columbia Hydro and Power Authority and Bonneville Power Administration, "Canadian/U.S. Interchange Capability Study: Progress Report," April 1980.

[14] The Alberta government has given its support to the prebuild concept, but with a distinct preference for the advancement of hydro projects as opposed to coal-fired generation projects. See for example recent remarks by David Smith (Chairman, Alberta Electric Marketing Agency) on "Financing Utility Construction" In Electricity Transactions Between Western Canada and the United States: Transcript of Proceedings (Napa, California: Saloman Brothers, May 1982), pp. 45 - 46.

[15] The U.S. demands in Chapter 3 are based on discrete blocks of power received in the importing regions. Given transmission losses, Canadian utilities would have to dedicate an amount of capacity greater than 1000 MW. This is accounted for in our analysis.

[16] This 5000 GW.h figure corresponds roughly to 1000 MW (or 1 GW) of capacity operated at an annual capacity factor of 57 percent, as given by the formula:

$$\text{Energy (GW.h)} = [\text{Capacity factor (\%)} \times \text{Capacity (GW)} \times 8760 \text{ (hrs/yr)}]$$

Interruptible energy sales are expressed in terms of an amount of surplus energy on the system, rather than a specific amount of capacity and associated capacity or utilization factor.

[17] Specifically, the cost of Canadian coal-fired generation does not include the cost of scrubbing, or flue gas desulfurization,

to control sulfur emissions (which produce acid rain). Nuclear costs include a factor for irradiated fuel management comprising temporary on-site storage, transportation, immobilization and long-term geological disposal. The potential effects of scrubbing and other environmental costs on Canadian delivered cost (and potential net revenues) will be discussed in Chapter 6.

As for the corresponding U.S. costs (which enter the calculation of export price), the cost of nuclear fuel includes waste disposal while the cost of new coal-fired generation includes scrubbing. The scrubbing costs are based on the Environmental Protection Agency's original New Source Performance Standard of 1.2 lbs. SO_2 per million Btu (see Appendix D).

[18] An example of a social opportunity cost approach would be to cost fuels at their value in export markets. This approach could result in significantly higher costs than the direct costs of these resources to the utility.

[19] We do, however, use social discount rates in calculating amortized capital costs of dedicated facilities (see below).

[20] A mill is one-tenth of a cent.

[21] Amortizing or annuitizing the capital cost of generating or transmission plant involves converting an in-service cost into an equivalent annual amount such that the full cost may be recovered over a designated time period (usually the estimated life of the plant). This is done using a 'capital recovery factor' (CRF):

Annual Capital Cost (ACC) = Capital cost (\$MM) x CRF (1/yrs)
(\$MM/yr)

$$\text{Where CRF} = \frac{r}{1 - (1 + r)^{-T}}$$

r = real discount rate (4%, 7%, 10%)
T = amortization period (70 years hydro station)
(40 years nuclear station)
(35 years coal-fired station)
(25 years transmission plant)

The base case real discount rate is 7 percent, with 4 percent and 10 percent for sensitivity purposes (see Appendix H). Transmission lines and stations are amortized over the maximum term of a National Energy Board licence, in keeping with the rule for oil and gas pipelines. Generating stations are amortized over estimated useful lives, since we are assuming that the plants are dedicated to export over their entire lifetimes (as opposed to being prebuild facilities).

[22] Saskatchewan is also interconnected with the United States by a new intertie with North Dakota (see Table B.3). Although intended

for an initial 100 MW seasonal diversity exchange with Basin Electric Coop, this intertie may be used to export small amounts of interruptible energy until 1985, and perhaps greater amounts beyond that date. But Saskatchewan has been excluded from the analysis because of data limitations (see Appendix H).

[23] Ontario Hydro, "Transmission Planning Processes," Memorandum to the (Ontario) Royal Commission on Electric Power Planning with respect to the Public Information Hearings (Toronto: Ontario Hydro, June 1976), p. 55. Intermediate stations are not required for a DC link because it provides an asynchronous interconnection between AC systems, and so avoids the stability problems associated with interconnected systems which do not operate in synchronism. See the discussion under 'Quebec' in Section 4.1.

[24] In its interruptible sales to New York (classified as 'fuel replacement energy'), however, Hydro-Quebec has consistently commanded a price of 80 percent of PASNY's decremental cost.

[25] In a sense, there is some precedent for pricing dedicated exports as given by the 'unit power agreements' in practice in the United States. The New Brunswick Electric Power Commission has adopted this type of agreement for its exports from Coleson Cove and Point Lepreau. Essentially, electricity is priced to cover accounting and production costs (interest, depreciation, operation and maintenance, and fuel) and a suitable return on equity investment. As a further example of pricing rules for capacity-type sales, 'short-term firm power' (see Glossary) generally includes a 'capacity charge' or 'demand charge'--which may be related to the seller's cost and/or the purchaser's alternative, but usually the former--and an 'energy charge' of incremental cost plus 10 percent. Had its proposed firm export deal with General Public Utilities not been cancelled, Ontario Hydro would have employed an annual capacity charge and a split savings energy charge based on the difference between the incremental cost of the utility's coal-fired generation and the cost of modern oil-fired generation in the United States. See National Energy Board, "Reasons for Decision In the Matter of the Application Under Parts I, III and VI of the National Energy Board Act of Ontario Hydro," Appendix 7, March, 1982.

[26] These capacity factors affect the delivered cost of dedicated exports since they enter the calculation of 'unit energy cost for capital amortization' (see above under Section 4.2.1). The capacity factor for dedicated capacity is a representative base load capacity factor. The capacity factors for dedicated energy correspond to the rates at which 1000 MW of capacity is demanded in the United States to displace oil. In computing delivered cost, these demand-side capacity factors are subject to assumed availability factors on Canadian generating units. In practice, the purchasing U.S. utility would be motivated to have the dedicated facility run at the highest feasible utilization factor. This is because, for hydro or nuclear at least, the incremental cost of running the station full-out is relatively insignificant.

[27] The extremely low incremental cost for hydro generation results from the assumption of run-of-the-river or spilled, as opposed to stored, energy. Hydro energy may be stored in reservoirs during off-peak periods for release during peak periods. In this case, the actual value of the energy to the utility is the cost of the fossil-fired peaking capacity (e.g., a gas turbine unit) displaced.

[28] The delivered costs to California were computed to be 48 and 46 mills/kW.h for Alberta and British Columbia, respectively, in comparison to a delivered price of 41 mills. Calculations were also made for the Pacific Northwest (WSCC-NWPP) where 4500 MW of nuclear additions are projected under the mid growth scenario (from Table C.7). The delivered costs of dedicated capacity turned out to be 37 and 33 mills, respectively. With a demand price of 41 mills, the corresponding unit net revenues were 4 and 9 mills per kW.h.

[29] This case assumes no change in reserve criterion between independent and integrated operation. Under the 20 percent reserve criterion, all of the paired regions display total capacity savings in excess of 2000 MW (under the low growth scenario) except for New Brunswick/New York which shows 1000 MW in shared savings (see Table 3.3).

[30] The capital cost of an HVDC link and the transmission distances between participating regions are taken from Appendix J.

[31] The summation across provinces for each export type is valid. That is, each of the U.S. regions considered could absorb 1000 MW capacity blocks from all its prospective suppliers in the year 2000, with the following exceptions:

(i) only 1600 MW of dedicated capacity is demanded in NPCC-New York under the mid growth scenario; and

(ii) under the low growth scenario, dedicated energy is demanded at capacity factors less than 50 percent in MARCA and NPCC-New York (but, even then, Canadian delivered cost comes in under the marginal cost of oil).

[32] Energy Analects (Don Mills, Ontario: Corpus), April 9, 1982, pp. 1 - 2.

[33] This time frame constraint is relevant also for generation. With lead times of up to 14 years (in the case of nuclear power stations), the 1990 study year for dedicated exports may be unrealistic. For this reason, we concentrate on the study year 2000.

[34] Ibid., June 5, 1981, pp. 3 - 4.

Chapter 5

ECONOMIC IMPACT

The potential of the United States as an export market for Canadian electricity was detailed in Chapter 3. Chapter 4 showed that a substantial export potential exists in those provinces currently exporting power--New Brunswick, Quebec, Ontario, Manitoba and British Columbia--but that Newfoundland, Nova Scotia, Saskatchewan and Alberta could also benefit directly from expanded power generation geared to U.S. needs. The purpose of this chapter is to describe economic impacts of key concern to policymakers associated with increased electricity exports. The issues are discussed under three headings: (1) income and employment, (2) exports of electricity versus other commodities, and (3) balance of payments.

5.1 Income and Employment

This section of the report examines the impact on the provincial and national economies of electric power exports. The economic impact is delineated in terms of both income and employment. Input-output analysis decomposes the economic impact into three effects: direct, indirect and induced.

- Direct effects are those which involve factor payments by electricity producers including wage payments to workers and capital payments such as profit and capital cost allowance;[1]
- Indirect effects occur in those industries that supply operating and maintenance inputs to electricity producers as well as the subsequent rounds of supplying their suppliers; and
- Induced effects are the increase in economic activity generated by the spending of household income (wages, salaries and supplementary labour income, and net income of unincorporated business).

The economic impact of additional exports derives from two sources:

- the purchase of Canadian electric power by U.S. utilities; and

- the capital expenditures involved in construction of generating stations to meet additional export demand.

First, the economic impact of export revenue derived from electricity sales from all provinces except Prince Edward Island is discussed. This is followed by an assessment of the impact of capital expenditures for four typical generating stations.

The primary tool of analysis is Statistics Canada's 1974 version of its Interprovincial Input-output model.[2] Regional input-output tables are extremely costly to construct. The 1974 model (released in 1980) is the most recent Canadian interregional model available. By using this model, the origin and type of impact of goods and services used in the construction and operation of electric power generating stations can be calculated. This allows one to estimate economic impact by region. The Statistics Canada Interprovincial Input-output model is an accounting framework based on the production structure and trade patterns of the Canadian economy in 1974. A detailed description of the method of analysis, assumptions and measures of economic impact is contained in Appendix K.

The strength of this type of analysis lies in the comparison of economic impacts. The input-output framework provides a consistent set of assumptions and model specifications; hence the relative impacts across regions or commodities can be estimated.

The model produces several measures of the impact of exports on provincial and national activity. Income impacts are shown because income is the most comprehensive measure of economic welfare used in assessing macroeconomic impact. Employment impacts are also indicated since jobs are of special concern to policymakers, particularly during times of high unemployment.

The economic impact of an additional $1 million of electricity demand is summarized in Table 5.1 and shown graphically in Figures 5.1 and 5.2. For example, Figure 5.1 indicates that $1 million of electricity demand in 1980 from Manitoba (for domestic consumption or export) will generate $1.1 million[3] of income to Manitoba residents and $1.3 million of income to residents of Canada as a whole. Similarly, Figure 5.2 indicates that 14 man-years of employment would be created in Manitoba and 17 man-years in Canada by $1 million of additional electricity consumption. Impacts on the producing (exporting) provinces--Quebec, Ontario, Manitoba, Alberta and British Columbia--are the largest, exceeding $1.1 million. Saskatchewan and

TABLE 5.1

IMPACT[a] OF $1 MILLION ELECTRICITY DEMAND BY PROVINCE, 1980

	Income[b] (thousands of 1980 dollars)		Employment (man-years)	
	Provincial	Canadian	Provincial	Canadian
Newfoundland	950	1080	7	10
Nova Scotia	760	1040	16	23
New Brunswick	750	1030	13	20
Quebec	1110	1240	13	16
Ontario	1110	1200	15	16
Manitoba	1110	1290	14	17
Saskatchewan	990	1250	12	17
Alberta	1100	1240	12	15
British Columbia	1130	1260	14	16

[a] Direct, indirect and induced effects are included.

[b] The income measure is Gross Domestic Product at Market Prices.

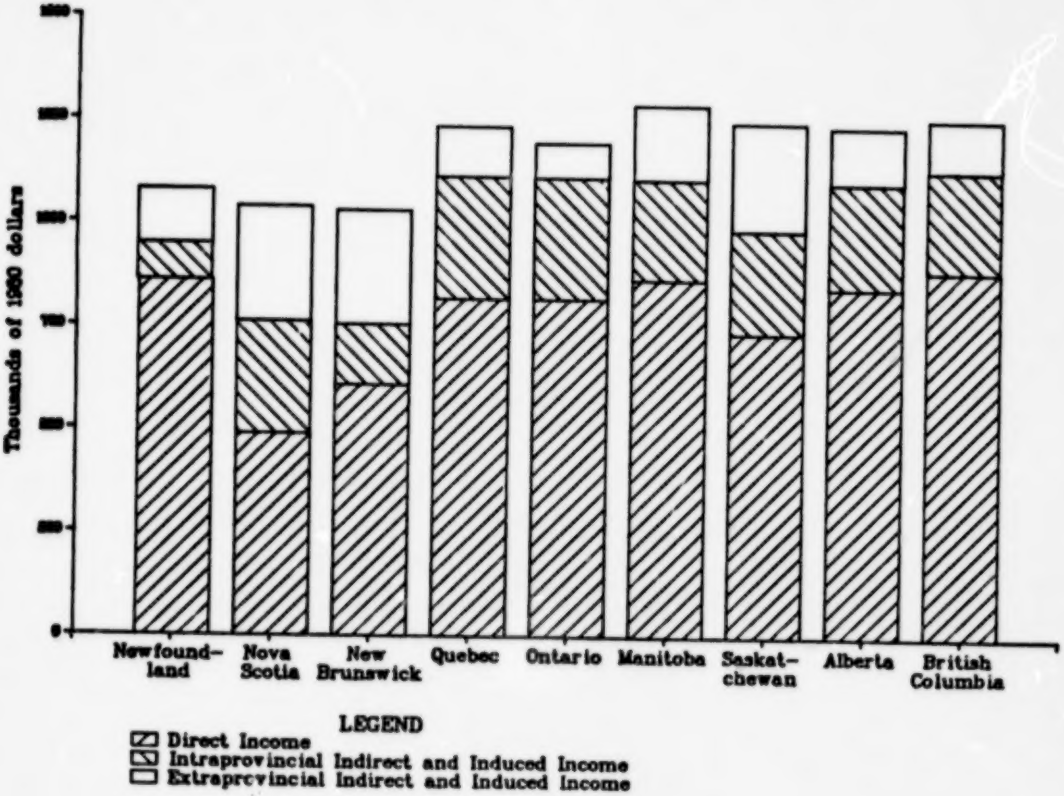

Figure 5.1: Impact on Income of $1 Million Electricity Demand

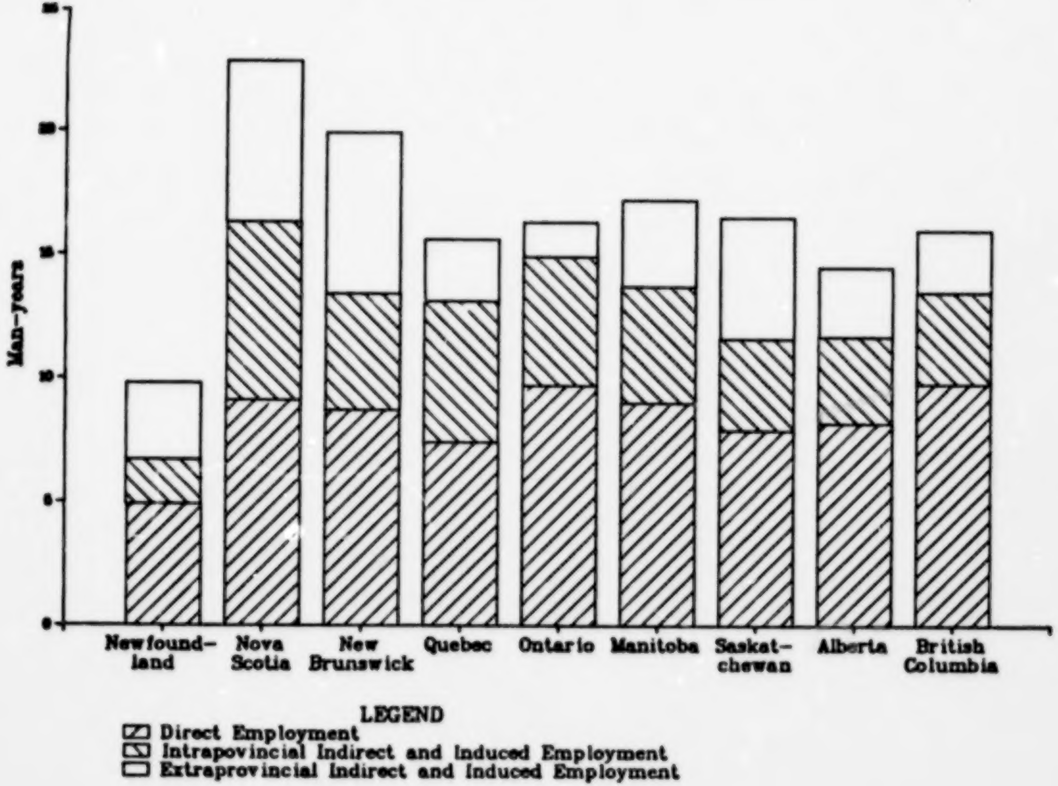

Figure 5.2: Impact on Employment of $1 Million Electricity Demand

Newfoundland show a somewhat smaller impact and the impact on New Brunswick and Nova Scotia is the least.

The input-output model allocates revenue from electricity sales into four major components: household income, business income, government income, and purchases of goods and services. Thus, payment for electricity covers not only operating costs (household income, government income, and purchases of goods and services) but also capital costs (business income, i.e., profit and an allowance for depreciation). For this reason the results shown in this chapter more accurately represent the impact of dedicated and firm power exports, since the charges for these types of sales include capacity components.

In order to interpret the results of the input-output analysis, it is important to understand certain elements of the structure of the model and the key assumptions used to derive results. It is most likely that additional electricity exports in the 1980s and 1990s will be supplied from hydroelectric sources in Newfoundland, Quebec, Manitoba and British Columbia, by nuclear power generation in New Brunswick, by coal-fired thermal plants in Nova Scotia, Saskatchewan, and Alberta and by coal or nuclear in Ontario.[4] However, the model assumes that any increment to electric power demand will be supplied according to average production from the generating mix in place in 1974. Table 5.2 shows the production of electricity in 1974 by province and fuel type. A similar table (Table 5.3) for 1980 indicates the changes in fuel use between 1974 and 1980. Table 5.4 indicates proposed additions to capacity for the period 1981 - 1990.

New Brunswick has added oil-fired capacity such that this fuel accounted for 64 percent of electricity production in 1980 versus 38 percent in 1974. The addition of the Point Lepreau nuclear facility will increase the province's capacity by 23 percent.

Ontario has added nuclear and coal capacity resulting in a 1980 production profile split evenly between nuclear, hydro and fossil-fired sources. The addition of almost 8000 MW of nuclear capacity is proposed between 1981 and 1990, an increase of 30 percent to Ontario's generating capacity. In 1974 over 50 percent of the province's electric power production was hydro-generated.

Saskatchewan and Alberta added coal-fired generating facilities in the period to 1980 and were even more reliant on coal in 1980 than they were in 1974. Facilities in Nova Scotia continue to be dependent

TABLE 5.2

ELECTRIC POWER PRODUCTION IN 1974[a]

	Coal		Nuclear		Other Thermal		Hydro		Total
	GW.h	Percent	GW.h	Percent	GW.h	Percent	GW.h	Percent	GW.h
Newfoundland	0.0	0	0.0	0	0.5	2	27.9	98	28.4
Nova Scotia	1.2	24	0.0	0	3.1	62	0.7	14	4.9
New Brunswick	0.5	11	0.0	0	1.9	38	2.5	51	5.0
Quebec	0.0	0	0.0	0	0.1	0	64.3	100	64.4
Ontario	20.1	26	13.9	18	5.0	6	39.8	51	78.8
Manitoba	0.1	1	0.0	0	0.0	0	14.2	99	14.4
Saskatchewan	3.3	47	0.0	0	0.8	11	3.1	43	7.2
Alberta	7.7	56	0.0	0	4.2	31	1.7	13	13.6
British Columbia	0.0	0	0.0	0	0.2	1	23.5	99	23.8
Canada	33.0	14	13.9	6	30.3	7	178.2	74	241.4

SOURCE: Canada, Statistics Canada, Electric Power Statistics, Volume 2, Catalogue 57-202 Annual, 1974.

NOTE: Totals may not add due to rounding.

[a] Net generation of electric utilities after deducting station service.

TABLE 5.3

ELECTRIC POWER PRODUCTION IN 1980

	Coal[a]		Nuclear		Other Thermal[a]		Hydro		Total
	GW.h	Percent	GW.h	Percent	GW.h	Percent	GW.h	Percent	GW.h
Newfoundland	0.0	0	0.0	0	1.4	3	44.9	97	46.3
Nova Scotia	2.6	38	0.0	0	3.3	49	0.9	13	6.9
New Brunswick	0.7	8	0.0	0	5.9	64	2.7	29	9.3
Quebec	0.0	0	0.0	0	0.2	0	97.6	100	97.8
Ontario	31.0	28	35.9	33	3.0	3	40.2	36	110.1
Manitoba	0.4	2	0.0	0	0.0	0	19.1	98	19.5
Saskatchewan	5.8	63	0.0	0	0.8	9	2.5	28	9.2
Alberta	16.9	72	0.0	0	4.8	21	1.7	7	23.4
British Columbia	0.0	0	0.0	0	2.5	6	40.9	94	43.3
Canada	57.4	16	35.9	10	22.4	6	251.0	68	366.7

SOURCE: Canada, Department of Energy, Mines and Resources, Electric Power in Canada 1980 (Ottawa: Electrical Branch, 1981).

NOTE: Totals may not add due to rounding.

[a] Estimated values

TABLE 5.4

PROPOSED ADDITIONS TO GENERATING CAPACITY, 1981-1990
(megawatts)

	Coal	Nuclear	Other Thermal	Hydro	Total
Newfoundland	0	0	25	84	109
Nova Scotia	300	0	0	23	323
New Brunswick	0	630	0	0	630
Quebec	0	685	24	11 284	11 993
Ontario	710	7 731	154	54	8 649
Manitoba	0	0	0	0	0
Saskatchewan	300	0	0	252	552
Alberta	2 725	0	0	0	2 725
British Columbia	0	0	0	3 143	3 143
Total	4 035	9 046	203	14 840	28 124

SOURCE: Canada, Department of Energy, Mines and Resources, Electric Power in Canada 1980 (Ottawa: Electrical Branch, 1981), and utility sources.

on imported oil, although there has been an increasing use of Cape Breton coal, a trend which will continue in the 1980s.

Newfoundland, Quebec, Manitoba and British Columbia generated electricity predominantly from hydroelectric sources both in 1974 and 1980. British Columbia is planning an increase in generating capacity of about 30 percent by 1990, all of which will be hydraulic.

One would expect the results of the input-output analysis to be more accurate for provinces whose generation mix has shifted the least since 1974. Thus the analysis discussed here may be more meaningful for the provinces of Newfoundland, Quebec, Manitoba and British Columbia, relative to Nova Scotia, New Brunswick, Ontario, Saskatchewan, and Alberta.

Provinces dependent on imported fuels (Nova Scotia, New Brunswick and to a lesser extent Ontario) show a smaller income impact. If increased electricity exports from Ontario and New Brunswick were to be supplied totally by nuclear power generation and those from Nova Scotia by coal thermal generation, with all imported fuels for electric power generation purposes eliminated, the income impact with regard to those provinces would be greater than shown. Indeed, the impact would be more comparable to that shown for the western provinces and Quebec.

Saskatchewan has been partially dependent on Alberta coal. In Figure 5.1 this shows up as a smaller in-province impact but approximately equal national impact. If Saskatchewan were to use its lignite deposits to generate power for export, the in-province impact would be greater, without significantly affecting the national impact.

Most variations in the employment impact are attributable to regional differences in productivity of supplying industries. Direct employment by electric utilities is about the same in all provinces except Newfoundland. (Newfoundland generates a substantial amount of electricity from one hydro site, Churchill Falls.) If, as is likely to be the case, increased export demand is supplied by large coal, hydro or nuclear generating stations, the Canadian employment impact of export revenue remains relatively constant across provinces--at about 17 man-years per $1 million electricity export sales.

Several important impacts are omitted from the analysis because of the limitations of the input-output model. These include:

- stimulus to government activity resulting from tax earnings and demand for government services;
- stimulus to capital investment in the economy resulting from business earnings and demands on capacity; and
- opportunities for import substitution as a larger Canadian market develops for imported goods and services.

Because of these omissions, the true economic impact of exports will tend to be greater than that shown. In the case of electricity exports, the second factor is most important because the electric utility industry is very capital intensive. The model assumes that only household income is respent, and household income is a relatively small portion of total income for electric utilities. Typically, for Canadian utilities, less than one-third of direct income is in the form of household income. Therefore, the analysis has been extended to examine the impact of the construction of generation and transmission facilities.

The construction of electricity generating facilities to meet export demand will have a major impact on the provincial and national economies. Table 5.5 illustrates the impact of such construction expenditures. The Lennox generating station in Ontario is oil-fired. However, the capital requirements in terms of total expenditures and commodity purchases of an oil-fired thermal plant are very similar to those of a coal-fired station of equal capacity. Thus, the impact of constructing Lennox serves as a good estimate of constructing a coal-fired station in Ontario. Comparing Lennox to Genesee, a proposed coal-fired generating plant in Alberta, the national impact in terms of income and employment is roughly the same per dollar of capital cost. The location of many goods-supplying industries in Ontario--especially the primary metal, metal fabricating and electrical products industries--results in large income and employment impacts in that province whenever generating facilities are constructed in any given province. For this reason, Lennox has a greater intraprovincial impact than Genesee. Also, with its greater installed capacity and cost, a facility such as Lennox should have a greater absolute impact.

5.2 Exports of Electricity Versus Other Commodities

In assessing the contribution to regional economic growth of one commodity versus another, it is commonly accepted that manufacturing or further processing of raw materials is preferred. With

TABLE 5.5

IMPACT OF $1 MILLION CONSTRUCTION EXPENDITURES FOR GENERATING FACILITIES

	Capacity (MW)	Income[a] (thousands of $1980)		Employment (man-years)	
		Provincial	Canadian	Provincial	Canadian
Thermal Plant in Alberta[b] (Genesee)	1 125	570	1 170	20	44
Hydroelectric Plant in Manitoba (Limestone/ Conawapa)	1 080	790	1 250	34	52
Nuclear Station in Ontario (Bruce "A")	2 960	1 190	1 360	40	47
Thermal Plant in Ontario (Lennox)	2 232	1 210	1 380	38	44
Transmission Line in Prairie Provinces (Western Grid)	N/A	690[c]	1 090	27[c]	42

SOURCE: (1) Data (rounded) from Ontario Hydro, and (2) Marvin Shaffer and Associates Limited, Western Electric Power Grid Benefit Study: Socio-Economic Impact Analysis, (Vancouver: October 1980).

[a] The income measure used is Gross Domestic Product at Factor Cost.
[b] Expenditures on power plant, coal mine and transmission line.
[c] Manitoba, Saskatchewan and Alberta.

regard to electricity exports this position is summarized by the statement that 'the export of electricity is equivalent to the export of jobs'. This is based on the notion that the export of raw materials may help to create foreign jobs and income as processing and manufacturing activities are carried out in other countries rather than at home. According to this argument, electricity is a raw material best used as input to domestic manufacturing processes.

Benefit comparisons from the export of electricity versus aluminum, iron ore versus steel, copper concentrate versus copper wire, and other examples are often made. In each case a detailed cost-benefit analysis is required to determine the relative economic profitability of the two alternatives. Furthermore, in the electricity case, the total benefits of exports must be measured against the benefits of exporting other commodities, including the electricity used in producing them.

In this section we assess the relative contribution to regional and national income and employment of various export products. Figure 5.3 compares the impacts resulting from additional sales ($1 million) of hydroelectric power, aluminum, and lumber and timber in British Columbia. Aluminum and lumber and timber were chosen because they embody large amounts of energy relative to other goods. The direct income includes factor payments associated with the production of $1 million of product. The indirect income includes factor payments associated with supplying industries, but not induced effects arising from the respending of incomes.

Additional electricity demand will generate more direct income but less indirect and induced income in British Columbia than comparable demand for aluminum or for lumber and timber (see Figure 5.3). The impact of aluminum exports is relatively lower due to imports of alumina and bauxite ore. Looking at lumber and timber, it is clear that the indirect and induced impact on other B.C. industries is especially large. However, the direct income generated is less than that from electric power sales. The export of electricity does not have large interindustry effects, but it does generate substantial income. The total direct, indirect and induced income generated in British Columbia is largest for electricity demand and least for aluminum demand. Induced income arises from the respending of factor incomes. In the input-output model, payments to households (wages, salaries, supplementary labour income and net income of unincorporated business) are spent, generating additional economic activity. Induced income is

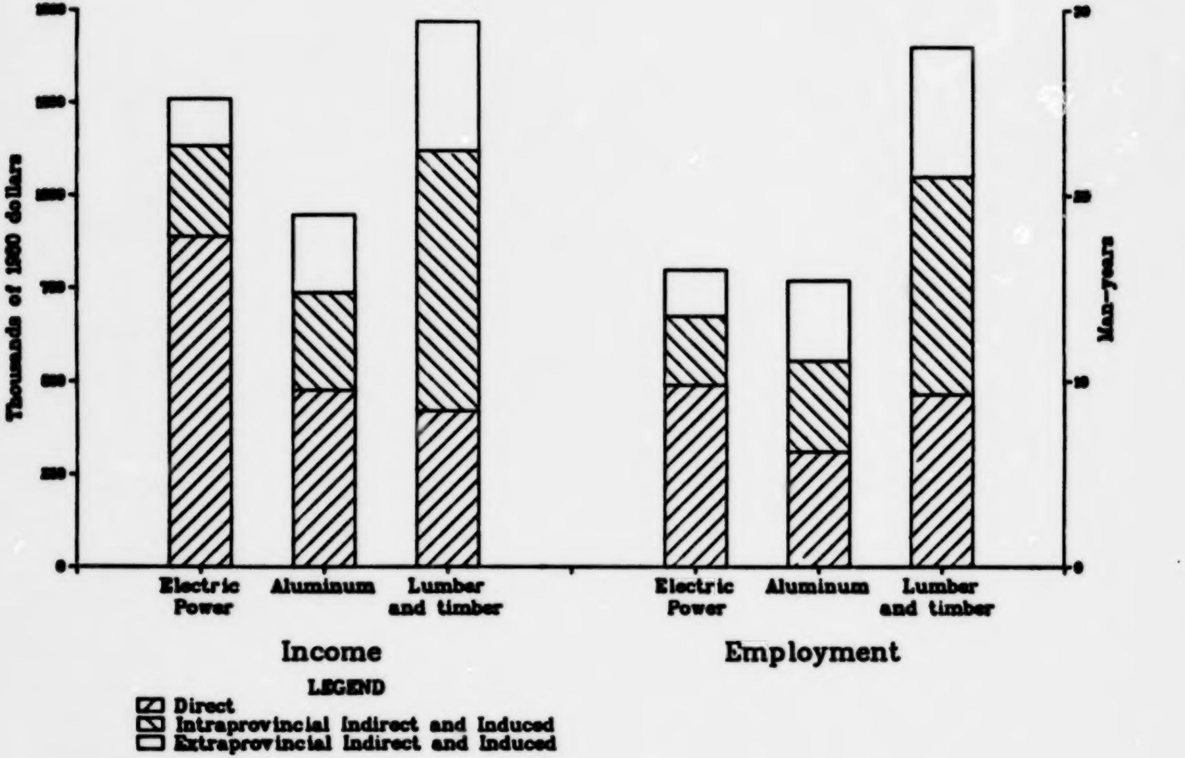

Figure 5.3: Comparison of $1 Million Demand: British Columbia

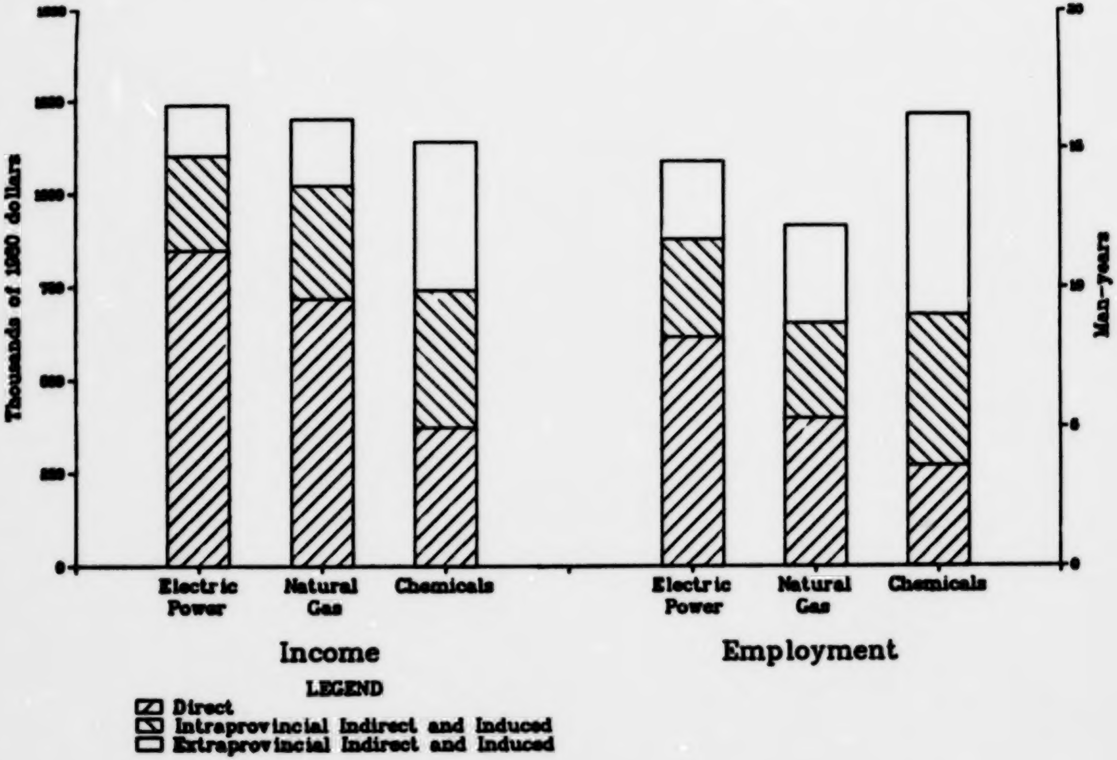

Figure 5.4: Comparison of $1 Million Demand: Alberta

largest in the lumber and timber example because this industry, and its major supplier the forestry industry, are labour intensive relative to aluminum and electricity.

Multipliers can be calculated with these results. The most common multiplier is the ratio of direct, indirect and induced effects to direct effects. From Figure 5.3 the income multiplier for electricity demand is 1.27 for the province of British Columbia and 1.42 for Canada.[5] Note that the provincial multiplier includes interregional feedback effects.[6] These multipliers are somewhat less than those for aluminum, 1.55 and 2.06 respectively, and substantially less than the 2.67 and 3.50 calculated for lumber and timber. Ranking commodity exports by magnitude of multipliers favours lumber and timber over aluminum and aluminum over electricity. However, electricity generates more direct, indirect and induced income in B.C. than either aluminum or lumber and timber per dollar of sales. Looking at employment, lumber and timber has a much larger employment impact because both aluminum production and electricity generation are very capital intensive activities. Thus, the choice of ranking criteria can affect the judgment of which export commodity is most beneficial.

Evaluating the relative merits of electricity exports versus aluminum, lumber and timber, natural gas, automobiles or other exports on the basis of a comparison of multipliers is misleading. More than a comparison of the income and employment impact is required for a complete economic assessment of the export of electricity versus other commodities. For example, the case of electricity versus aluminum in British Columbia requires analysis of the economic prospects for aluminum and electricity in international markets and the location of electric generation facilities. Alcan is planning to increase its smelter capacity at Kitimat, B.C. sometime in the late 1980s. The additional electricity requirement can be met by a 207 MW expansion of the company's Kemano plant, which currently has a capacity of 813 megawatts.[7] Unless electricity capacity is required by plants other than Alcan, additional exports of aluminum will not affect electricity exports. Benefits from aluminum and electricity exports can both occur simultaneously. In this case the export of electricity does not imply that jobs are lost in the aluminum industry just because more electricity is exported.

Alternatively, if additional electricity generating capacity is required for aluminum plants other than the one at Kitimat, then it is possible that electricity exports could reduce the electricity available for exports of aluminum or other products. If the capacity of a hydro facility in B.C. Hydro's expansion plan could be used either to generate power for export or to produce other export commodities, a detailed economic assessment of the specific alternative would be required to determine the relative economic advantages. Electricity exports have the potential to generate substantial net revenues for B.C. Hydro, possibly permitting rate reductions (see Chapter 4 for detail). In comparison, production of aluminum using the electricity of a generation project will create the income and employment associated with the construction and operation of electricity facilities plus the employment and income created in constructing and operating an aluminum smelter.

The major economic advantage resulting from electricity exports is the potential net revenue (i.e., total sales less generation cost) obtained from selling electricity at U.S. replacement prices.[8] In Chapter 4, it was shown that B.C. Hydro could earn between 33 and 51 mills/kW·h ($1980) in net revenues from firm oil-displacing (dedicated energy) sales to the United States.[9] These net revenues are based on the shipment of power from Site C on the Peace River in northern British Columbia to the California-Nevada subregion of the United States. Some combination of electricity supply to domestic aluminum producers and export to lucrative American markets will likely generate the maximum job and income impacts in British Columbia. A similar approach is required to assess the economic merits of exports of electricity versus other commodities for the other Canadian provinces.

In Figure 5.4 electric power is compared with natural gas and chemicals (including petrochemicals) in Alberta. Royalty payments on natural gas production are included in provincial indirect income. Demand for electricity (primarily coal-fired thermal power) creates more direct, indirect and induced income than equivalent demands for natural gas or chemicals. Direct, indirect and induced employment in Canada resulting from purchases outside Alberta by the chemicals industry is larger than the Canadian employment impacts for electricity and natural gas.

Figure 5.5 shows that an increase in electricity demand will create more income both in Ontario and the other provinces relative to an equivalent increase in iron and steel or automobile demand. These two industries require substantial imports, thereby reducing the potential domestic impact. In terms of employment, the direct effects are greatest for electricity but the indirect and induced effects are greater for iron and steel and automobiles.

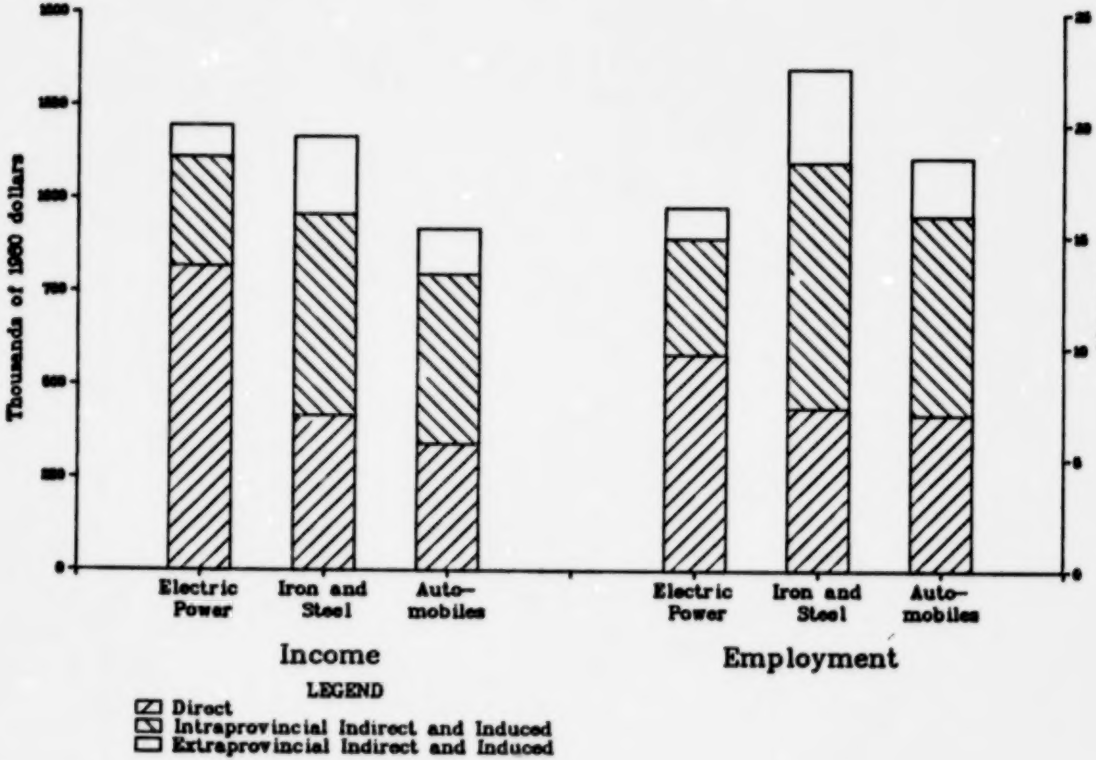

Figure 5.5: Comparison of $1 Million Demand: Ontario

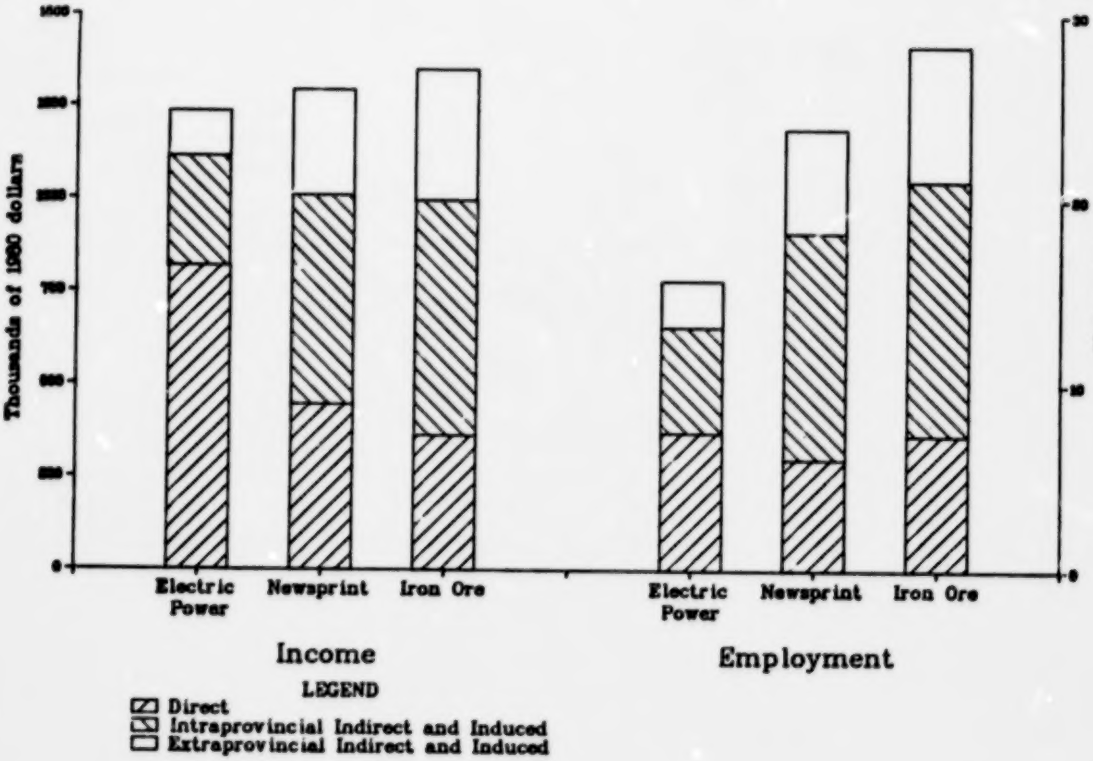

Figure 5.6: Comparison of $1 Million Demand: Quebec

In Quebec demand for iron ore or newsprint has a smaller impact on income than does electric power, as shown in Figure 5.6. However, the impact on other provinces' income (primarily Ontario's) is greater for iron ore and newsprint. Direct employment in electricity production exceeds that of iron ore or newsprint production but the indirect and induced effects on employment are significantly less from incremental electricity demand.

For the province of New Brunswick, the impacts of demand for electric power and fish products are compared in Figure 5.7. Direct income generated by the sale of electricity exceeds that generated by a comparable sale of fish products. However, the indirect and induced income impacts more than offset this direct effect. Due to lower productivity in the fish products and supplying industries, the impact on employment from the sale of fish products is greater than from the sale of electric power.

In conclusion, it has been shown that the economic impact of electricity exports is significant and compares favourably with other export commodities. Moreover, even in cases where electric power impacts are smaller, one cannot conclude that such exports are not worthwhile or should be sacrificed at the expense of other manufactured commodities. To the extent that electricity exports and other industries compete for materials and factors of production (e.g., there are electricity supply constraints), decision-making will require attention not only to job and income impacts but also to international market conditions, growth potential, and other important factors. Indeed, policymakers may find electric power exports a useful tool for economic development because, relative to other export industries, there may be considerable room for expansion.

5.3 Electricity Exports and the Balance of Payments

Through the 1980s, the decline in domestic oil production and the increasing price of foreign sources of crude oil are likely to result in a very substantial increase in the cost of net oil imports.

Failure to reach oil self-sufficiency at an early date will be particularly costly to Canadians if there is another curtailment in the inbound flow of foreign crude oil. However, even without an oil supply crisis our continued dependence on large volumes of foreign crude will place a heavy burden on Canadians. For example, the tax to subsidize Canadian consumers may have to be increased as the net cost of oil imports grows. The crude oil import compensation charge averaged

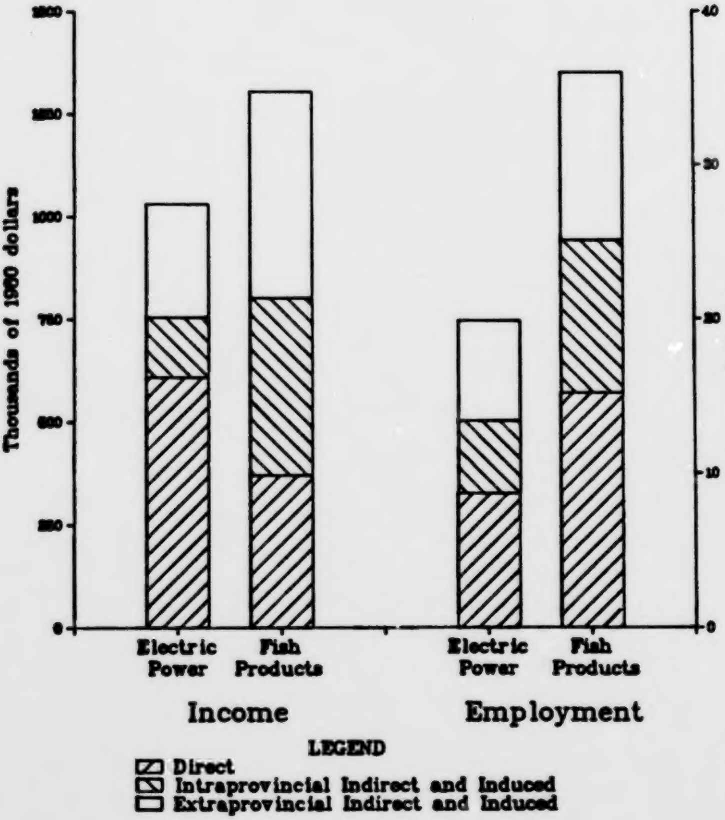

Figure 5.7: Comparison of $1 Million Demand: New Brunswick

$21.04 per barrel in 1980.[10] Total compensation paid to importers in 1980 was $3 billion.[11] Moreover, the larger balance of payments deficit will almost certainly necessitate higher interest rates and/or a lower exchange rate than otherwise in the short term.

One way in which the negative economic repercussions of the oil trade balance problem may be offset is, of course, through sharp increases in Canadian non-conventional oil production. This, however, will take considerable time. Meanwhile, increased exports of electric power can provide a stabilizing influence on the exchange rate and/or domestic interest rates. Because of the lengthy lead times inherent in constructing generating facilities, virtually all such increases would have to involve export from existing surplus capacity in provincial systems. Indeed, there is significant potential for increased exports through 1990, as a result of continued U.S. reliance on oil-fired generation. To achieve this potential, the problems of inadequate transmission capacity, competition from other supply sources and regulatory constraints must be alleviated.

Increased electric power exports directly enhance the balance of payments position by bringing revenue into the country. Export sales from surplus provincial capacity not only improve the net revenue position of the exporting utilities but also may be used to reduce their need to borrow in foreign capital markets. The associated reduction in foreign debt-servicing costs lowers the cost of imported services imputation in the current account of balance of payments, further improving Canada's foreign trade position.

In the case of dedicated plants, in the short run (during the construction phase), the impact would be adverse due to the outflow of cash for commodity imports of machinery and equipment. This impact could be mitigated by the inflow of capital if financing involved borrowing in international capital markets. However, over the longer run the foreign exchange earned through the life of a generating station would exceed the cost of goods imported for construction and debt service payments abroad. Thus, any increase in electricity exports would tend to lower a balance of payments deficit.

Balanced seasonal diversity exchanges are neutral with respect to the balance of payments. Exports during one period of the year are offset by imports during other periods. To the extent that new capacity is delayed, there will be some effects in the longer run due to capital flows and machinery purchases foregone.

The direct impact of electric power exports on the balance of payments depends, of course, on the volume of such exports and their price. In 1980, 28.2 billion kilowatt-hours of electric energy were exported--the equivalent of the output of 6500 megawatts of capacity operated at a fifty percent capacity factor. If this volume were to be doubled by 1990, the balance of payments improvement in that year compared with 1980 would be about $2.3 billion. The 1980 current account deficit was $1.1 billion.[12] This calculation is based on the assumptions that the additional exports will not be generated by the use of imported fuels and that the export price of electric power will average about $80 per thousand kilowatt hours in 1990. Electricity exports have the potential in the next two decades to reduce dramatically or even to eliminate our persistent and growing current account deficit.

Canada's net trade in crude petroleum and electric power is summarized in Table 5.6. The deficit in oil has been growing during the 1970s and will continue to increase through the 1980s. Similarly, our trade surplus in electric power has increased rapidly, a trend that will likely be maintained in light of recent export commitments by several Canadian utilities (e.g., Quebec's major 13-year export deal with the Power Authority of the State of New York, concluded in March 1982).

TABLE 5.6

NET TRADE[a]
(millions of dollars)

Year	Crude Petroleum	Electric Power
1976	- 994	153
1977	-1465	362
1978	-1884	477
1979	-2092	728
1980	-4020	770
1981	-5357	1117

SOURCE: Canada, Statistics Canada, Exports, Catalogue 65-203 Annual and Imports, Catalogue 65-202 Annual.

[a] Exports less imports, Trade of Canada basis.

Table 5.7 indicates the relative importance of some of Canada's major export commodities. In 1980 electric power exports accounted for one percent of total merchandise exports, about one-fifth the value of natural gas exports and one-tenth the value of automobile exports. There is greater growth potential for electricity exports than for most other export commodities.

One may ask why Canada should be interested in strengthening trade ties with the United States. With the U.S. already accounting for about two-thirds of Canada's exports, should not more emphasis be placed on developing trade with other countries? This raises several interesting points. First, the Canadian dollar appreciated significantly during 1981 vis-a-vis major European currencies. This has tended to slow Canadian sales abroad and to reduce the flow of foreign exchange dollars needed to finance Canada's current account shortfall with the United States. Increased exports of electricity would provide a stream of U.S. dollars which would be welcomed even without this turn of events. In any case, electricity cannot, because of physical and cost constraints, readily be exported to countries other than the United States. However, the expansion of electricity intensive goods production to serve the export market ('embodied' exports of power) is one way to increase electricity exports to European and other overseas countries.

It has been concluded elsewhere that balance of payments considerations alone are not a sufficient justification for increased exports of any commodity.[13] Increased exports lead to only a temporary improvement to the balance of payments for they are offset, sooner or later, by adjustments in other exports, in imports or in capital flows through exchange rate adjustment or other mechanisms. That balance of payments effects have repercussions on the economy is not in question, but the ultimate impact is determined by government fiscal, monetary and exchange rate policies.

The important impact of increased electricity exports lies in its effects on income, employment, regional disparities and other indicators of economic welfare. Our economic analysis (Chapter 4) indicates that exports meet the necessary efficiency criterion cited by Powrie for investment in any commodity production activity for export. Substantial exports of electricity will result in many indirect effects on employment, investment, the exchange rate, interest rates and other macroeconomic variables. However, in a small open economy such as Canada's, it has been argued that a stable exchange rate should be a principal pillar of monetary policy,[14] and there can be no question that an inflow of foreign exchange revenues would assist Bank the of Canada in its activities to support the Canadian dollar.

TABLE 5.7

EXPORTS OF ELECTRICITY AND OTHER COMMODITIES, 1980[a]

	Millions of Dollars	Percent
Total Merchandise Exports	76,159	100.0
Electricity	793	1.0
Automobiles	7,458	9.8
Natural Gas	3,984	5.2
Newsprint	3,684	4.8
Lumber and Timber	3,353	4.4
Iron and Steel	2,042	2.7
Chemicals	2,032	2.7
Aluminum	1,533	2.0
Iron Ore	1,343	1.8
Fish Products	1,251	1.6
Merchandise Trade Balance[b]	8,488	--
Current Account Balance[b]	-1,096	--

SOURCE: Canada, Statistics Canada, Canadian Statistical Review, Catalogue 11-003E Monthly.

[a] Trade of Canada basis.

[b] Balance of Payments basis.

Footnotes

[1] Normally direct effects should also include the effects on suppliers of operating and maintenance goods and services to electricity producers. These effects have been included in indirect effects because of difficulties in calculation. Moreover, in the case of electricity exports, these effects are likely to be relatively small.

[2] An increase in production of electricity for export will likely affect generation costs as well as the rate and debt structure of power utilities. Utility profits obtained from exports will, depending on the financial structure, result in lower rates and/or debt payments. The EMR interfuel substitution model was examined for analyzing these provincial financial impacts but the model results available were not realistic. See R. W. Erdman, "Electricity Pricing Model" (Ottawa: Department of Energy, Mines and Resources, September 1977).

[3] All dollar amounts in this chapter refer to constant 1980 Canadian dollars.

[4] In Nova Scotia the use of Bay of Fundy Tidal Power may be a viable alternative. In addition, hydroelectric projects are planned in Saskatchewan and Alberta.

[5] These are calculated as follows. Direct income is $889. Indirect and induced income for British Columbia and Canada are $244 and $369, respectively. The income multiplier for British Columbia is therefore (889 + 244) ÷ 889 or 1.27 and for Canada (889 + 369) ÷ 889 or 1.42.

[6] Expenditures in one province have an impact on all other provinces. The economic activity generated in these other provinces can in turn affect activity in the province where the original expenditures took place. This latter effect is interregional feedback.

[7] British Columbia, Ministry of Energy, Mines and Petroleum Resources British Columbia Energy Supply and Requirements Forecast 1980-1995 (Victoria: Energy Resources Branch, April 1981), p. 4 - 159.

[8] Or, more correctly, U.S. replacement prices less the cost of transmission from the Canadian generating facilities to the U.S. regions.

[9] These net revenue estimates pertain to export from the proposed Peace Site C development for the 1990 study year. The range in net revenue is based on the use of alternate discount rates, world oil price scenarios, and U.S. demand growth scenarios. See Tables 6 through 11 in Appendix I.

[10] Canada, Department of Energy, Mines and Resources, "Canada-Alberta Energy Pricing Agreement; Supplementary Information on Energy Pricing and Volume Assumptions" (Ottawa: Energy Strategy Branch, September 1981).

[11] Canada, Statistics Canada, National Income and Expenditure Accounts, Catalogue 13-001, First Quarter 1981, Text Table I.

[12] Ibid., Table 7. The current account balance includes merchandise trade (generally in surplus) and services (including interest and dividends and miscellaneous investment income, freight and shipping and net tourism expenditures).

[13] T. L. Powrie, Energy Policy and the Balance of Payments: An Outline of the Issues, Study No. 6 (Calgary: Canadian Energy Research Institute, July 1979).

[14] Ronald I. McKinnon, "The Exchange Rate and Macroeconomic Policy: Changing Postwar Perceptions," Journal of Economic Literature, Volume XXIX (June 1981): 531-557.

Chapter 6

OTHER CONSIDERATIONS

In the preceding three chapters we have: 1) analyzed quantitatively the potential size of the U.S. market; 2) determined whether these markets could be economically tapped by potential Canadian suppliers; and 3) investigated the economic impacts of increased exports and compared these impacts against the impacts of other export commodities. The purpose of this chapter is to address qualitatively a number of other important issues raised in Chapter 1 which are not as amenable to formal economic analysis. These issues are addressed under two major headings: implications for electric utilities and implications for Canada as a whole.

6.1 Implications for Electric Utilities

6.1.1 Disposition of Revenue

There are at least four possible scenarios for the disbursement or application of the net revenues from electricity export sales:

- a reduction in rate structures facing domestic customers;
- a lowering of external financing requirements for capacity expansion, with the result that future rate increases would be dampened;
- establishment of special funds for conservation, mitigation of environmental damage, etc.; and
- appropriation in whole or in part by the provincial or federal government through taxation.

The first two applications constitute direct benefits to utility customers, whereas the latter two represent indirect benefits in the form of increased public services or lower future tax burdens which may arise out of the recycling of export revenues. These applications are not mutually exclusive and some combination of the above could occur in practice.

In the case of taxation, there would be a redistribution of revenue from the exporting utility to the government. Under the pricing rule adopted in this study for sales from dedicated plants

(100 percent of U.S. replacement cost, for illustrative purposes) the full incidence of any given tax would fall on the Canadian utility, since the contractual price to the U.S. customer could not be increased in order to absorb a portion or all of the tax. Under the split savings formula applied to interruptible energy, on the other hand, the tax would normally be borne equally by the exporting and importing utilities.[1]

Presumably, a tax could also influence the volume of electricity exports. Not only could taxation affect the feasibility of any prospective sale, but it could threaten the profitability of existing contracts in cases where taxes were to be applied retroactively. For Canadian and U.S. utilities contemplating power transactions, the possibility of retroactive taxation interjects a degree of uncertainty into the export picture. Contracts could, however, be structured to deal with such uncertainty.

6.1.2 Flexibility in Planning

One of the planning dilemmas facing electric utilities is the 'structural overcapacity' associated with load forecasts. Lead times for planning, constructing and licensing new capacity are growing relative to the range of reliable demand forecasts. This makes it increasingly difficult to match capacity and load expansion. Moreover, there is evidence that the costs of overcapacity are considerably less than the costs of blackouts, 'brownouts', and other supply disruptions which can result from undercapacity.[2] In predominantly hydro systems, this overcapacity problem is compounded for those utilities which build for 'critical water' conditions, with the result that surplus capacity is available during average or high water years.

In planning their capacity expansion, utilities can regard export markets as buffers for surplus capacity. Indeed, most of Canada's electricity exports in recent years have been based on excess capacity due to domestic loads which have been lower than anticipated. These exports provide revenue to alleviate the cost of generating facilities which would otherwise sit idle throughout the year. The same holds for capacity which is temporarily idle during a system's off-peak season (e.g., summer). In this case, seasonal diversity exchanges with systems experiencing their peak loads in opposite seasons can allow for year round use of facilities.

But aside from exporting surplus capacity on an ad hoc basis, utilities could actively plan with export markets in mind and thereby attempt to 'fine-tune' their planning processes.[3] We have already discussed the capacity and production cost savings which could follow from increased seasonal diversity interchange. In addition, the option of dedicated exports could permit smaller utilities to achieve economies of scale through the installation of larger generating units or facilities than would be required for domestic loads.[4] More generally, utilities could better coordinate demand and capacity growth by prebuilding facilities, dedicating them to external markets in the medium to long term, and repatriating them when additional power was needed domestically. The advantage of prebuilding is that the lead times to renegotiate export contracts should be considerably less than those to commit new facilities.[5] As a result, the planning horizon for capacity additions, and the attendant risks of overinstalling capacity, could conceivably be reduced.

Of course, both dedicated exports and seasonal diversity interchange would require greater cooperation between utilities in the planning and operation of their networks. Utilities could be reluctant to surrender planning autonomy. Furthermore, there could be problems associated with different approaches to forecasting and, perhaps more importantly, different policies on conservation and environmental regulation between Canada and the United States.

6.2 Implications for Canada as a Whole

6.2.1 Environmental Costs

It is generally held that some of the 'social costs', including environmental costs, of electric power generation and transmission are understated in normal utility accounting of costs. This practice reflects the problems associated with incorporating such costs into an economic analysis, rather than a viewpoint that they are not important or potentially substantial. Consequently, these concerns are typically (as in this study) addressed qualitatively as negative 'third party effects' or 'externalities', although ideally it would be more appropriate to internalize costs of this nature in both economic analyses and utility accounting procedures.

The potential external costs of electricity production and transmission include flooding of public lands from hydro developments, storage and long-term disposal of nuclear spent fuel, 'acid rain' from coal-fired generation, and amenity losses of recreational and wilderness land due to transmission corridors.[6] It is difficult, if not impossible, to assign a reliable unit (mill per kW.h) cost to these types of impacts. A major difficulty in undertaking a quantitative assessment of environmental impacts is the limited state of knowledge regarding the effects on health and environment of low levels of chemical and radioactive pollution and regarding the probability of nuclear accidents.

In this section the following issues are investigated:

- What is the relative magnitude of the incremental environmental costs from increased electricity export sales?
- Would including these costs in the potential net revenue calculations of Chapter 4 jeopardize the economic viability of such sales?
- Do major differences in these environmental and health costs exist across electricity export sales and generation categories?

The external costs of electric power can arise from generating plant construction and operation, and transmission line construction. In relative terms, nuclear and coal-fired generation would tend to impose higher environmental costs in their operating rather than their construction phases, while the opposite would hold for hydro generation. As for cost differences across export types, one would expect the environmental impacts of interruptible energy and diversity interchange to be less than those from dedicated exports, in the sense that these two types of sale would not entail the construction of new facilities specifically for export.

On the basis of a cursory review of some U.S. studies[7] of coal and nuclear environmental costs ('damage costs') and on the basis of selected Canadian estimates[8] of the costs of more stringent emission control standards ('avoidance costs') for fossil fuel-fired plants, we suggest that environmental costs would be less than 20 mills/kW.h (1980$ Canadian). Therefore, internalizing these costs in the analysis of Chapter 4 would not severely jeopardize the viability of oil-displacing (dedicated or interruptible energy) exports to the United States. However, the unit net revenues for dedicated capacity sales to displace new U.S. coal or nuclear capacity have been shown to be less than those for oil displacement and could be jeopardized for some regions,[9] depending on more precise estimates of environmental costs. (It should be recognized that, in some instances, the cost of environmental damage could be less than the cost of mitigation, in which case corrective measures would not be cost-effective from a society-wide perspective).

It is likely that the environmental costs of electric power generation will constitute a greater proportion of supply costs in the future as a result of:

- the imposition of more stringent pollution control, health and safety standards, etc.; and
- the increasing value, relative to other consumer goods and services, that society will place on non-market-priced amenities such as recreational and wilderness land.

Moreover, due partly to regulatory and information lags, government regulations do not adequately internalize the environmental and health costs of electricity production. In sum, the negative external costs of electric power generation are a subject of much public sentiment but limited concrete information. This disparity widens when exports of electricity are at issue.

The production of other commodities destined primarily for export (e.g., petrochemicals, iron and steel) also entails environmental damage costs which are not effectively internalized by the industries involved. It is tacitly assumed that, in such cases, the practice of society at large bearing the environmental costs is in the regional or national interest. It is not clear why a different course is often argued with respect to electricity exports.

6.2.2 Taxation

Electricity exports represent potential sources of taxation revenue to both the federal and provincial governments. The prerogative to tax power exports lies with the federal government under section 91(3) of The Constitution Act (see Appendix A). Provincial governments are empowered to levy taxes on electricity sales in general, including sales to the U.S. market. However, provincial taxes cannot discriminate between electricity used within the province and electricity exported. The rationale for taxing electricity is basically threefold:

- to provide a general revenue source;
- to encourage efficiency and conservation by raising the effective price of electricity to its replacement cost; and
- to price electricity to include a greater proportion of the 'social costs' of generation

The second rationale relates primarily to domestic sales (which are priced according to the average cost of electricity),[11] while the first and third reasons apply to domestic and export sales alike. Governments at both the provincial and national levels are presently faced with an economic downturn and growing budget deficits. In such a financial climate, taxes on electricity sales represent a tempting source of revenue.

As for the efficiency argument, there is some recent evidence that higher (real) electricity prices would lead to significant drops in residential and industrial consumption.[12] In the short term, an action of this nature would increase the extent of surplus generating capacity. In the longer term, the utility supply response could mean cancellation or postponement of much of the new capacity in expansion plans, reducing future surpluses available for export.[13]

Efficiency was one of the justifications provided by the Quebec government in March of 1981 for its royalty scheme aimed at appropriating Hydro-Quebec profit. Finance Minister Parizeau declared that electricity rates should rise in keeping with price increases in alternative power sources such as oil and gas. He then took steps to have Hydro-Quebec pay the province a 'dividend' out of the resulting net revenue increases.

Other provincial governments have recently increased or are planning to increase the water taxes charged to utilities generating power from hydroelectric resources. In December 1981, the B.C. Ministry of Environment raised water licence fees in British Columbia with the argument that hydro projects should cover the social cost of generation or, in other words, the value of these resources in alternative uses (e.g., wilderness, recreation, agriculture).[14]

6.2.3 National Goals

Increased electricity exports would clearly have implications for policy goals with regard to energy supply and demand in Canada. In its National Energy Program: Update 1982,[15] the federal government outlined the role of electricity in oil substitution, in the fostering of regional development, and in the provision of a source of export revenue to offset the cost of imported oil. Regarding the off-oil program, it was stated that there was sufficient surplus capacity in provincial electric power systems such that neither the advancement of non-oil generation projects nor the imposition of major restrictions on electricity exports was expected to be necessary. However, the federal government did announce that it was willing to consider the prebuilding of nuclear plants, and that in particular it would consider providing financial support for New Brunswick's Lepreau 2 station which would be built initially to serve export markets. Other Atlantic projects which could serve the off-oil objective in the longer term include the Lower Churchill hydro development in Labrador and Bay of Fundy tidal power in Nova Scotia. As mentioned in Chapter 4, the northeastern United States could potentially supply both the financial aid (i.e., either in the form of export revenues or direct capital investment) and the expanded market to justify projects of this scale.

The notion of federal approval of prebuild projects is not new. Canada's National Power Policy, which was established in 1963, specifically acknowledged the potential for building "large-scale remote hydro or other power projects" ahead of domestic needs and then for exporting blocks of firm power over extended periods of time.[16] What distinguishes the National Energy Program announcement is the priority given to prebuild nuclear plants, reflecting Ottawa's desire to preserve the CANDU nuclear system. The CANDU option is viewed as a means of expanding Canada's long-term energy options, while at the same time developing domestic resources and technology. Because of depressed reactor sales abroad and inadequate demand at home, export-dedicated plants are now being contemplated in order to provide interim support for Canada's nuclear industry.

The updated National Energy Program also referred to the importance of strengthened interprovincial interconnections and to the possibility that the federal government would help to finance the Western Grid between Manitoba, Saskatchewan and Alberta.[17] There has been considerable interest in east-west power ties since 1974, when Ottawa announced its willingness to help in the funding of related studies and projects. A 1978 study by the Interprovincial Advisory Council on Energy (IPACE) - An Evaluation of Strengthened Interprovincial Interconnections of Electric Power Systems[18] - examined the net benefits from a high voltage transmission network between the provinces which could allow for such benefits as time zone diversity exchanges, reserve-sharing, fuel cost savings through coordinated operation of generating resources, and enhanced security of supply. Based on 1977 load forecasts supplied by provincial utilities, the study's conceptual plan for transmission revealed a "modest net economic advantage...particularly if fuel prices continue(d) to escalate relative to other costs."[19] Subsequently, most provincial demand forecasts have been adjusted downward; nonetheless, the prospect of a 'national grid' is still appealing to many Canadians and several utilities are proposing to increase their interprovincial transfer capability (see Chapter 2 and Appendix B).

One of the implications of a policy of increased interprovincial ties centers on the tradeoffs between east-west and north-south power flows. Over the years international interconnections have proved more viable given the transmission distances separating provincial systems. U.S. export markets have been particularly attractive because of higher oil prices and because of the greater potential for cost savings from north-south seasonal diversity than from time diversity within Canada. However, this is not to assert that east-west and north-south transactions are mutually exclusive. The IPACE study group, for its part, recommended an 'optimal' interconnection strategy whereby planners would first establish that level of interprovincial transfers which maximized total Canadian benefits, and would then determine international sales so as to increase this collective benefit.[20]

Two other goals of the National Energy Program which relate specifically to oil and gas but which have been cited by some authorities as applying equally to electricity are security of supply and conservation. In particular, some Canadians worry that our overall energy security could be jeopardized by the export of electricity generated from nonrenewable resources like coal and uranium. Estimates of domestic coal resources by Energy, Mines and Resources Canada indicate supplies substantially in excess of current requirements. In addition, Ontario Hydro has access to a reasonably secure supply of eastern U.S. coal. As for uranium, existing reserves would appear to be more than sufficient to meet domestic needs and to maintain Canada's position as a major world supplier. Moreover, a policy of dedicated nuclear exports would probably require further exploration and development effort, which could well increase reserves through the stimulus provided to Canada's uranium mining industry.

When it comes to conservation, the effect of increased electricity exports is ambiguous. A number of Canadian utilities have established 'conservation funds' and conceivably these could be financed from export profits. But to the extent that revenues were to go toward subsidizing domestic rates, exports could increase the consumption of electricity.[21] However, it must be remembered that the goal of energy conservation is selective in nature and specifically directed towards those energy forms in short supply. Lower domestic electricity prices could induce existing or prospective oil and gas consumers to switch to electricity. Therefore, in terms of a national conservation policy aimed at reducing oil consumption, electricity could be a useful substitute for foreign and domestic oil supplies.

Another issue of national interest is the so-called 'open tap' issue which hinges on the apprehension that increased electricity exports would lead United States customers to expect contract sales volumes to continue indefinitely. This is not a legal issue of 'vested rights' since no property or contractual interest is granted under a National Energy Board export licence and each licence is subject to a fixed term and set of conditions (see Appendix A). Moreover, the licensing process is based on the principle of 'first right of refusal' to Canadian customers; that is, utilities must demonstrate that prospective exports are surplus to domestic needs, including the needs of neighbouring provinces. Rather, the open tap issue is political in nature and reflects the perception that electricity exports could be used in political bargaining between the U.S. and Canadian governments.

A final policy matter which deserves some consideration is the long-term impact of electricity exports on a Canadian 'industrial strategy'. One facet of the 'export of jobs' argument (see Chapter 5) is that cheaper electricity from Canada acts to improve the competitive advantage of U.S. industry. This argument has been extended to the use of Canadian capital to finance export facilities. Specifically, it has been suggested that extensive Canadian financing of export-dedicated power plants would free American capital for investment in vanguard technologies or industrial renewal. Then, after several years, Canada might find that it had enjoyed a cash-flow beneficial to its balance of payments but that, relative to the United States, much of its capital stock was tied up in mature technologies. (This line of reasoning would not apply, though, if facilities were financed by U.S. utilities.)

Strictly speaking, such a freeing of U.S. capital would only occur over the construction period of the plant. However, the argument is worth noting to the extent that lucrative dedicated exports could create a bias towards towards 'hard' technologies like nuclear power in Canada. Of course, as mentioned above, revenues could be channelled into special funds for the development of alternative energy sources such as solar power. Moreover, it is likely that an 'optimal' industrial strategy would entail the joint promotion of domestic manufacturing industry and technology, and electricity sales abroad. Indeed, export sales would assist in expanding regional resource and industrial bases, including domestic high technology (e.g., through the CANDU industry).

In this chapter, we have brought together and discussed some 'non-economic' issues with regard to increased electricity exports which were raised in Chapter 1. In the next chapter, we will summarize the economic analysis of Chapters 3 through 5, and provide a number of recommendations concerning public policy and areas for further research.

Footnotes

[1] Some U.S. utilities argue that an export tax constitutes a benefit to Canada and that, therefore, the whole tax should be borne by the Canadian utility.

[2] Recently, there has been considerable literature on 'over/under' planning models which evaluate the tradeoffs between customer outage costs and the costs of maintaining higher reserve margins. See for example M. L. Baughman and D. P. Kamat, Assessment of the Effect of Uncertainty on the Adequacy of the Electric Utility Industry's Expansion Plans, 1983-1990, Interim Report for the Electric Power Research Institute by the Center for Energy Studies at the University of Texas, Report EA-1446 (Palo Alto: EPRI, July 1980); Decision Focus, Incorporated, Costs and Benefits of Over/Under Capacity in Electric Power System Planning, Final Report for the Electric Power Research Institute, Report EA-927 (Palo Alto: EPRI, October 1978); and A. P. Sanghvi, "The Economic Costs of an Electricity Supply and Demand Imbalance," Paper Presented to the Economics Section of the Canadian Electrical Association (CEA), Spring Meeting, Winnipeg, March 8, 1982.

[3] Most Canadian public utilities do not presently have mandates to plan for export and, therefore, this would require changes in government/regulatory policy.

[4] New Brunswick's Point Lepreau 1 is an example of economies of scale through access to external markets.

[5] By this we mean that facilities could be built and dedicated to export over medium term (5 to 10 years) contracts, which would be of shorter duration than the lead times (including regulatory approval) on most generation projects. At the end of the contract term, the exporting utility could evaluate its domestic requirements and decide whether to renew the contract or repatriate the facility for its own needs. This could also apply to the exercising of an option within an existing contract or licence which allowed the exporter to repatriate power on the occurrence of certain events. Presumably, however, such options would not be particularly welcomed by U.S. utilities substituting Canadian for domestic generating capacity. Indeed, in the case of capacity displacement, the lead time advantage translates into a disadvantage from the American perspective. That is, U.S. importers could be faced with capacity shortfalls if lead times to alter the supply of Canadian electricity were shorter than those for installing new domestic capacity.

[6] For descriptions of environmental costs of nuclear and coal-fired electric generation see: Farhood Rahnama, Coal and Nuclear Electricity Fuels: A Regional Analysis, Study No. 15 (Calgary: Canadian Energy Research Institute, June 1982), Appendix B, and William Ramsay, Unpaid Costs of Electrical Energy: Health and Environmental Impacts from Coal and Nuclear Power, Study Prepared for the National Energy Strategies Project (Washington: Johns Hopkins University, 1979).

[7] One study estimated the human costs of U.S. coal and nuclear generation to be roughly 10 percent of total capital and operating costs. See L. Gaines, R. S. Berry and T. V. Long II, TOSCA: The Total Social Cost of Coal and Nuclear Power, (Cambridge, Massachusetts: Ballinger, 1979), pp. 70 - 71.

One should note that U.S. estimates are not directly applicable to the Canadian situation due to differing sulfur contents of coals, different population distributions and densities, enriched versus natural uranium, etc.

[8] A recent study estimated the (1979 $ Canadian) utility costs of complying with strict emission control standards to be 15, 14, 8, 5 and 5 mills/kW.h for Nova Scotia, New Brunswick, Ontario, Saskatchewan and Alberta, respectively. See Shawinigan/Intergroup, "Air Emission Control Options: Canadian Utility Cost Impacts," Volume I, Report Prepared for the Canadian Electrical Association (Montreal: Canadian Electrical Association, November 1979), p. 70.

[9] See Appendix I, Table 3.

[10] Due to increased public awareness and population pressure, and due to a decrease in the 'supply' of wilderness resources.

[11] The average cost pricing rule for domestic electricity prices involves rolling in the cost of new capacity with that of existing capacity. The replacement cost principle, on the other hand, involves pricing electricity at the cost of an additional unit of power or, alternatively, at the cost of new generation. The dedicated exports examined in Chapter 4 observe this latter principle since they are costed to cover the capital and operating costs of new generation and transmission facilities.

[12] Empirical analysis, as well as general post-OPEC experience, have indicated a significant price-responsiveness (price elasticity) of electricity consumption to higher electricity prices. For a survey of Canadian electricity price elasticities by region see DataMetrics Limited, "Canadian Regional Energy Demand Elasticities," Report prepared for the Economic Council of Canada (Calgary: DataMetrics, March 1982).

[13] For a discussion of the interaction between electricity rates and new capacity requirements see John F. Helliwell and Michael Margolick, "The Link between Electricity Prices and the Need for New Dams in British Columbia," Evidence Prepared for the B.C. Utilities Commission Site C Hearings (Vancouver: Programme in Natural Resource Economics, University of British Columbia, January 1982).

[14] *Electrical Business* (Toronto: Kerrwil), March 1982, p. 1.

[15] Canada, Department Energy, Mines and Resources, *National Energy Program: 1982 Update*, Ottawa, June 1982.

[16] Hon. Mitchell Sharp (former Minister of Trade and Commerce, Government of Canada), *Statement of National Power Policy*, October 8, 1963.

[17] The Western Grid has since been postponed indefinitely. See Chapter 2.

[18] IPACE Networks Study Group, Report to the Interprovincial Advisory Council on Energy, 2 Volumes, October 1978.

[19] Ibid., Volume I, p. 4.

[20] Ibid., Volume II, p. 69.

[21] It is sometimes argued that even without the effect of export revenues, domestic electricity rates are subsidized in three ways: (1) through the average cost pricing rule applied to electricity (see Note 11); (2) through the lower interest rates facing public utilities because their bonds are backed by provincial governments; and (3) through the exemption of electric utilities from federal or provincial corporate income tax. This subsidization is said to cause residential and industrial consumers to demand more electricity, rather than to invest in conservation measures or alternative energy sources which would be viable if the electricity subsidy were not in place. See for example Glenn P. Jenkins, "Public Utility Finance and Economic Waste" (Boston: Harvard Institute for International Development, October 1980).

Chapter 7

CONCLUSIONS AND RECOMMENDATIONS

The benefits and costs of Canadian electricity exports have been a subject of controversy encompassing financial, economic, environmental, legal and political issues. In this closing chapter, we summarize the regional potential for increased electricity exports and highlight some of the benefits associated with a more active national export policy. In addition, a number of recommendations on policy measures and areas for further research are presented.

7.1 Promising U.S. Markets and Canadian Sources of Supply

The most promising export market for Canadian electricity would appear to be the additional displacement of existing oil-fired generation in the United States. In terms of specific U.S. regions, this translates into the New England, New York, Mid-Atlantic Area Council (Pennsylvania, Maryland, etc.) and California-Nevada regions, where substantial oil-fired generation is expected to continue for the next two decades. Under a range of U.S. load growth projections, a total market in excess of 7000 megawatts is estimated to exist by the year 2000.

Although 70 000 megawatts or more of U.S. capacity additions--the vast majority of which being coal or nuclear--are planned for the 1990 to 2000 period, we view the market for displacing base load capacity as less attractive than the market for displacing oil. This is due to the fact that the marginal (i.e., operating) cost of oil-fired units is expected to be double the average total (i.e., capital plus operating) cost of new U.S. coal-fired or nuclear facilities. As for seasonal diversity interchange, there is potential for significant capacity savings between certain Canadian and U.S. regions, although this potential is constrained by diversity agreements already in place and possible competition from interruptible exchanges.

One may ask what incentive there is for American utilities to substitute Canadian electricity for domestic sources of supply. Aside from concerns about reliability, there is the argument that U.S. producers would be better off proceeding with their capacity expansion plans as opposed to 'postponing the inevitable' with firm or interruptible purchases from Canada. Some U.S. utilities, like their Canadian counterparts, are finding themselves in a position of surplus capacity (albeit much of it in the form of idle oil-fired capacity) due to demand growth lower than anticipated. Therefore, it seems likely that prospective American purchasers would make use of surplus capacity in either their own systems or neighbouring U.S. systems, rather than resort to foreign sources of supply. Furthermore, if the market for displacing oil-fired generation is so lucrative, why would U.S. utilities not build plants to serve this market? In answer to these questions, it appears that Canadian utilities could compete in the U.S. market for three main reasons:

- In general, Canadian utilities have been subject to fewer financing and regulatory difficulties than American utilities. These difficulties have been responsible for the wave of cancellations and deferrals of new capacity--and, in particular, new nuclear capacity--in U.S. expansion plans;
- In many cases, Canadian electricity demonstrates a cost advantage. For example, exports from new hydro and CANDU nuclear plants could be competitive with new coal-fired or nuclear facilities in the United States. Likewise, firm or interruptible sales from surplus hydro and nuclear capacity in Canada could compete with U.S. generation based on surplus oil-fired and coal-fired capacity, given the relatively low incremental operating costs of hydro and nuclear stations; and
- Using Canadian electricity to displace existing oil-fired generation is consistent with the U.S. energy policy of limiting imports of foreign oil.

Canadian utilities could exploit these export opportunities from three broad sources:

- firm sales from surplus domestic facilities;
- interruptible sales from surplus domestic facilities; and
- firm sales from facilities built for export purposes (i.e., export-dedicated plants).

Analysis indicates that all Canadian provinces, with the exception of Prince Edward Island, have significant untapped export potential. Specific options for dedicated exports include: hydroelectric or tidal projects in Newfoundland, Nova Scotia, Quebec, Manitoba and British Columbia; nuclear facilities in New Brunswick and Ontario; and coal-fired stations in Nova Scotia, Saskatchewan and Alberta. In addition, provincial utilities could pursue more traditional export paths using surplus capacity which has resulted from a drop in domestic load growth.

Newfoundland, Nova Scotia, New Brunswick, Quebec and Ontario could each earn large export revenues by displacing oil in the northeastern states, in particular, the power-hungry New England region. Alberta and British Columbia could access the California-Nevada market, which demonstrates the highest dependence on oil-fired generation. Presumably, this market would also be available to Manitoba and Saskatchewan, even though our analysis has matched these provinces with the MARCA states (the Dakotas, Minnesota, etc.) for reasons of transmission distance. However, one possibility not explored here would be a 'leapfrog' or 'swap' strategy for electricity sales. As an illustration, hydro power from Manitoba could be used to displace coal-fired generation in MARCA which, in turn, could be sent to California as a substitute for local oil-fired generation.

As mentioned earlier, the potential net revenues from displacing new capacity in U.S. expansion plans are considerably smaller than those from oil displacement. Although most U.S. regions are planning coal and nuclear additions in excess of 5000 MW between 1990 and 2000, the price for capacity displacement would be lower and consequently exporting utilities would earn less revenue on a unit (i.e., per kW.h) sale basis. Nevertheless, it appears that hydro capacity in Newfoundland, Quebec, Manitoba and British Columbia, and nuclear capacity in New Brunswick and Ontario, could economically displace new coal-fired and nuclear facilities in the northeastern states, the Midwest and the Pacific Northwest.

Seasonal exchanges between winter peaking Canadian regions and summer peaking U.S. regions would allow the participating utilities to defer new capacity in their expansion plans. Quebec and Ontario show the greatest potential for capacity savings of this sort, in conjunction with the MAIN (Illinois, Missouri, etc.), MAAC (Pennsylvania, Maryland, etc.) and New York regions. However, significant savings could also be available between Manitoba, Alberta and British Columbia, on the one hand, and utilities in MAIN, the southern portion of MARCA (e.g., Nebraska) and California-Nevada.

7.2 Potential Constraints On Increased Exports

When it comes to realizing these export opportunities, Canadian utilities could encounter certain technical and institutional constraints. A major constraint on increased electricity exports would be transmission capability. At present, six provinces--New Brunswick, Quebec, Ontario, Manitoba, Saskatchewan and British Columbia--have international interconnections. Existing interruptible sales are subject to the rating and loading of transmission lines, particularly within the United States. Any substantial increase in exports would call for transmission construction and reinforcement, and it is uncertain whether this could be achieved within a reasonable time frame, given the financial and regulatory problems facing utilities. In the United States, transmission construction takes capital funds away from much-needed generation projects. The situation is aggravated by overlapping regulatory jurisdictions and by the fact that transmission lines may have to cross neighbouring states which bear some of the environmental costs but receive none of the direct benefits of the imported power. Jurisdictional difficulties are less severe in Canada, where legislation will soon (pending a six-month lag) allow the National Energy Board to expropriate rights-of-way for interprovincial and international transmission lines.[1] Expropriation will be done only at the request of a province desiring access through another province, and will require a hearing.

A second potential constraint on increased exports relates to environmental and health considerations. Generally, electricity sales from surplus domestic capacity would give rise to fewer environmental and health costs than would exports which entailed new generating plant or transmission construction. Inadequate knowledge regarding the precise social costs of electric power generation have made it, and electricity exports in particular, the subject of some debate. Environmental groups argue that Canada should not bear the social costs of displacing U.S. generation. On the other hand, proponents of exports in Ontario for example, claim that coal-fired (or nuclear) capacity in their province could alleviate the acid rain problem by displacing outdated coal facilities in the northeastern United States.[2] In any case, it is essential that electricity exports (and all electricity sales for that matter) include a proper accounting of any quantifiable environmental damage or avoidance costs. These include the costs of compliance with pollution control standards, of nuclear spent fuel disposal and of compensation for flooding from hydro developments.

It is our opinion that the price which could be charged for oil displacement in the United States would be more than sufficient to cover costs of this nature. For any prospective electricity export, the environmental and other costs to Canadians must be balanced against the associated benefits before determining whether to proceed with the sale. However, one should assess the net social benefits of electricity exports on equal footing with other export commodities, the production of which may also entail adverse environmental impacts (e.g., petrochemicals, iron and steel).

Rivalry for lucrative U.S. markets may tend to limit Canadian electricity exports. An exporting province could face competition from fellow provinces, in terms of the cost at which power could be delivered to U.S. load centres.[3] It could also be obliged to compete against surplus hydro or coal-fired generation within the United States. As an example, in lieu of its cancelled export deal with Ontario Hydro, General Public Utilities of New Jersey will purchase power from old coal-fired plants on the Detroit River.

A further set of possible constraints on exports arises from the regulatory powers of the federal and provincial governments (see Appendix A). In Canada, either level of government could theoretically attempt to interrupt or curtail licensed electricity exports, or to influence the quantity of export through taxation. (This government curtailment after the granting of a licence is distinct from the case of exercising curtailment or interruption conditions which have been placed in a licence and are known to the purchaser prior to final commitment.) Provinces would essentially be limited to controlling the use of resources in electric generation and to levying taxes on all (i.e., no discrimination between domestic and export) electricity sales. Generally, the federal government's powers in this regard relate to its jurisdiction over export taxation, and over the licensing of exports and of the construction of interprovincial and international transmission facilities.

As for restrictions on these powers, exporters would have no legal recourse against curtailment of licensed exports since NEB licences do not confer contractual or property interests. International law channels would also raise difficulties, in the absence of specific treaty arrangements, and therefore it is more likely that injured parties would pursue government lobbying or private contractual remedies.

Whether these curtailment and taxation powers would be extensively exercised, and hence would constitute valid obstacles in the minds of prospective U.S. importers, is open to question. It is worth noting that to date the National Energy Board has never terminated an electricity export licence prior to maturity. Furthermore, electricity exports have been exempted from the Board's newly acquired powers to revoke export licences on grounds of 'public convenience and necessity'. Even if under exceptional circumstances (e.g., a national emergency) the federal government were to curtail any given export, it could face long-term repercussions in the form of reduced electricity, and perhaps overall, trade in the future. Presumably, the same sort of consideration could apply to the taxation of electricity exports. Since the major attraction of an electricity export tax is the lucrative revenue source it would provide, the federal government would be unlikely to set tax levels so as to jeopardize the feasibility of existing sales. In any event, export contracts could be specifically worded to deal with the possibility of retroactive taxation.

A potentially greater constraint on exports is political acceptance. In the United States, there is some political resistance to electricity imports on the basis that they would have negative impacts on regional employment and industry. In Canada, political uncertainties exist with regard to the concept of building for export. The federal government and a number of provincial governments (e.g., New Brunswick, Quebec, Ontario and Manitoba) have made clear their willingness to consider prebuild generation projects, while other provinces have so far been reluctant to accept such proposals on environmental or other grounds.

7.3 National and Regional Perspectives

Assuming that these constraints could be eased with the demonstration of direct net benefits to exporting and importing utilities, increased Canadian electricity exports would provide a significant stimulus to regional economic activities.

The regional (provincial) income impact of a $1 million rise in electricity export demand is estimated to range from $0.8 to $1.1 million in 1980, with provinces dependent on imported coal showing the smaller impacts. Regional employment impacts arising from this stimulus in demand range from 12 to 16 person-years (except for Newfoundland, which shows a lesser impact). Much of the machinery and equipment requirements associated with generating plant construction are met by Ontario and Quebec industry. Consequently these two provinces, as well as the resident province, receive significant economic benefits from generating plant construction.

In terms of economic impact, electric power exports compare favourably with a sample of other export commodities. The total Canadian income impact of a rise in electricity export sales is higher than that of a comparable increase in aluminum and automobile exports and lower than that of an increase in exports of fish products and lumber and timber. A greater share of this income impact remains in the province of origin, so that the total regional impact of increased power exports exceeds the impacts of most other commodities considered. As for job impacts, electricity exports tend to generate less employment than other export items (with the exception, here, of natural gas), especially for predominantly hydro provinces. This is due to the capital intensive nature of electricity production.

In the short term, increased exports would help to stabilize the exchange rate by providing revenue to offset our growing oil trade deficit, and it is conceivable that over the longer term they could reach such a level as to reduce considerably or even to eliminate this deficit. However, any balance of payments effects are of secondary importance relative to impacts on income, employment, regional disparities and other economic indicators.

An important employment-related issue concerns the tradeoffs between exporting electricity directly and exporting it in an 'embodied' form through products like aluminum. It is sometimes argued that power sales to the United States are made at the expense of electricity intensive industry in Canada, and therefore constitute an 'export of jobs'. We find little merit in this argument given the nature of the electric power and other manufacturing industries in Canada. As a general rule, international market rather than factor supply considerations (labour, capital, energy, etc.) have constrained the expansion of Canadian manufacturing. Since Canada is in a position of surplus with respect to existing and undeveloped generation resources, increased electricity exports would have little or no negative impact on the supply of power to domestic industry.[4] Moreover, under the National Energy Board's licensing criteria, Canadian industry has priority to any proposed electricity export.

It is likely that an 'optimal industrial strategy' for Canada would combine the promotion of electric power exports to the United States and the development of domestic electricity-using industry. Relative to other export commodities such as forest products and primary metals, electricity exports demonstrate a buoyant market and significant untapped supply potential.

Among the other possible benefits of increased exports to Canadian utilities, their customers and the country at large are:

- the application of export revenue to lower domestic electricity rates;
- a reduction in utility borrowing requirements (and the attendant costs of high interest rates) through the use of export revenue to finance expansion,[5] or through the deferral of new capacity due to seasonal diversity interchange;
- the construction cost savings, economies of scale, and greater planning flexibility which may be available from building generation facilities in advance of domestic needs;
- a stimulus to regional economic development (e.g., the manufacturing industry in Ontario, coal mining industry in Nova Scotia, uranium mining in Saskatchewan); and
- a means of rejuvenating the CANDU nuclear system which could help to develop domestic high technology, broaden Canada's industrial base and expand her long-term energy options

The extent of provincial control in the Canadian electric power industry renders exports a particularly useful engine of regional development in periods of economic recession. Furthermore, electricity is not as subject to geographical concentration as other Canadian industries, including energy-related industries like oil and gas. That is, all of the provinces considered here have access to generation resources from which they could exploit export opportunities.

In assigning national priorities to potential sources of export supply, attention must be given to economic, environmental and energy policy criteria. On the basis of the analysis in this study, we find that generally hydroelectric power exports produce the greatest net economic benefits to Canadian utilities, followed closely by nuclear power exports, and finally by coal-fired electricity exports. We base this conclusion on the following factors:

- the potential net revenues tend to be higher for hydro exports (i.e., the generation cost is lower--see Appendix I); and
- hydro is generally considered the most environmentally benign generation type in the sense that its environmental impacts are usually more certain and localized than those arising from nuclear or coal-fired generation. In

> addition, institutional frameworks have already been developed to provide mitigation or compensation for associated damage to private property.[6]

However, regional differences in resource endowments, supply costs and energy policy criteria may suggest a different ranking of hydro and nuclear power exports within a particular province. For example, transmission distances from generation sites to markets are such that the delivered costs of dedicated nuclear power from Ontario and Quebec dedicated hydro power are similar. Moreover, indications are Canada is in a considerable surplus position with respect to uranium and coal reserves. Our analysis indicates that nuclear and coal-fired exports which include a reasonable accounting of environmental and health-related costs can create positive net benefits to Canada and should therefore be considered along with hydroelectric exports.

In sum, then, this study finds that substantial economic benefits are available through increased power exports and that the regional economic impacts from these exports compare favourably with the impacts from other export commodities. Ultimately, in order to determine whether to pursue a more active export policy, governments will be called upon to make some social value judgements. In the past, public and political debate on electricity exports has tended to emphasize the potential adverse effects of these exports, in particular their environmental impacts. To a certain extent, this indicates an inconsistency in policy and public opinion because the same degree of critical assessment is generally not directed at other industries which impose such costs.

7.4 Policy Recommendations

Several policy recommendations flow from this study. These relate to the net benefits which could accrue from an expansion in electricity exports to the United States and, as well, to measures for reducing constraints on this expansion.

- We conclude that a more vigorous export policy would be in the national economic interest and therefore merits detailed investigation by utilities and governments. Our analysis of the potential costs and benefits of increased electricity exports indicates that they would contribute significant net benefits to Canadian citizens, electric utilities and the national and regional economies.

- Provincial governments should reassess their policies in light of the benefits which have been demonstrated. In

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- a stimulus to regional economic development (e.g., the manufacturing industry in Ontario, coal mining industry in Nova Scotia, uranium mining in Saskatchewan); and

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- We conclude that a more vigorous export policy would be in the national economic interest and therefore merits detailed investigation by utilities and governments. Our analysis of the potential costs and benefits of increased electricity exports indicates that they would contribute significant net benefits to Canadian citizens, electric utilities and the national and regional economies.

- Provincial governments should reassess their policies in light of the benefits which have been demonstrated. In some provinces, the dramatic increases in medium to long-term firm exports considered here would run counter to existing government policy (e.g., some utilities do not have a clear provincial mandate to build for export).

- We recommend that the Canadian government undertake an extensive information campaign to convince U.S. utilities (and other interested American parties) of Canada's willingness to enter into contractual obligations for firm power sales. Some prospective U.S. customers are reluctant to pursue firm purchases of Canadian electricity because they worry that the Canadian government could intervene to cut off licensed exports. However unfounded these concerns, they are real and must be alleviated.

- A national policy of increased electricity exports should be considered in conjunction with greater interprovincial power transfers. East-west and north-south power flows are not mutually exclusive. In fact, they could prove complementary to the extent that greater ties between the provinces lowered domestic reserve requirements and so increased the amount of surplus capacity available for export. From a national perspective, an integrated interprovincial-international power flow strategy would likely generate substantial economic benefits.

- We suggest that the electric utility industry develop a consistent approach and strategy vis-a-vis power sales to the United States and that the individual utilities work together to eliminate any misunderstanding of related issues on the part of governments and the general public. Moreover, Canadian utilities seeking to export electricity to the same U.S. market region should, insofar as possible, strive to coordinate and harmonize their efforts in order to maximize the net socioeconomic benefits to Canada. Several of the constraints on increased electricity trade are common to all Canadian utilities and provinces--for example, lack of market information, environmental concerns, and uncertainty regarding regulatory procedures. In the past, exporting utilities have tended to adopt a narrow perspective on international power sales in that they have concentrated on maximizing revenues for their own jurisdictions.

- Because electricity exports demonstrate net benefits to the country at large, the Canadian government should take the lead in establishing an institutional framework to encourage higher levels of export. This would include study into the detailed financial and legal arrangements for export, including the advantages of treaties and the feasibility of federal financing of prebuild projects.

7.5 Research Recommendations

We conclude with some suggestions for further research. The electricity demand and supply analysis provided here has been strictly illustrative, meaning that we have not attempted an optimal matching of potential exporters and U.S. markets. Moreover, not all types of electricity transactions have been formally analyzed.

Individual Canadian utilities would be advised to conduct their own investigation of promising markets and costing of alternative supply sources. From the broader international perspective, the determination of an 'optimal electricity export strategy' would be aided by a sophisticated interregional model which allowed for competition among Canadian provinces for U.S. markets, as well as for interprovincial and interstate power flows. Specific areas for additional research on electricity exports include:

- an analysis of other potential markets, e.g.,
    - the market for displacing existing U.S. coal-fired generation,
    - the market for displacing peaking capacity;
- the sensitivity of U.S. markets to various factors, e.g.,
    - domestic load growth projections,
    - market penetration by competing Canadian and U.S. suppliers,
    - economic growth forecasts;
- alternative pricing strategies for exports and the associated tradeoffs for both sellers and purchasers;
- the feasibility of transmission construction and reinforcement to serve interruptible markets; and
- alternative financial, legal and organizational arrangements for export, e.g.,
    - U.S. versus Canadian investment financing of prebuild projects,
    - export contracts versus international treaties,
    - utility-by-utility transactions versus the use of interregional power pools or international trading companies.

Our intention has been to identify and put into perspective the benefits and costs of increased electricity exports. It is hoped that this study will provide a base from which utilities, governments and individual citizens can conduct more detailed analysis of the contractual, regulatory, pricing, and costing arrangements of electric power export.

Footnotes

[1] This legislation (Bill C-108) was introduced in response to a recent court case in which TransAlta Utilities of Alberta sought to expropriate right of way for the Alberta-B.C. transmission line (see Appendix A, Section 2.2.). The act will also impinge on the dispute between Newfoundland and Quebec over a transmission corridor to export Labrador power. In fact, the six-month lag was designated to provide a breathing space in which the two provinces could settle their dispute privately.

[2] This follows from a previous commitment by Ontario Hydro to reduce it own acid rain emissions by installing scrubbing equipment within the decade. In fact, this commitment may now be in jeopardy as a result of the cancellation of Hydro's major export deal with General Public Utilities of New Jersey.

[3] The National Energy Board would not permit price competition between prospective exporters. Therefore, competition would likely be on the basis of delivered costs.

[4] In fact, electricity exports could even stimulate industrial activity if export revenues were used to reduce domestic rate structures or were appropriated by government through taxation and subsequently recycled into economic development.

[5] Unless exports entail the construction of new facilities, in which case Canadian utilities may have to borrow abroad, thereby increasing their debt-servicing payments.

[6] Of course, the environmental damage from hydro exports could in fact be minimal or nonexistent if exports entail existing surplus capacity or the construction of facilities which do not require additional flooding of river valleys.

APPENDIX A

CANADIAN ELECTRICITY EXPORTS: LEGAL AND REGULATORY ISSUES

Appendix A

CANADIAN ELECTRICITY EXPORTS: LEGAL AND REGULATORY ISSUES*

A.1 Introduction

This appendix examines the major legal constraints that would face Canada in any attempt to cut off export commitments of electricity to the United States. It should be emphasized that the issues being addressed here are matters of public law - i.e. what powers and constraints are associated with the different levels of government, and what redress is available against government by injured parties? We do not address the question of what would happen if private companies (including, for our purposes here, Crown corporations) were of their own motion to cut off exports. In that case, the aggrieved parties would of course be left with standard private law remedies relating to breach of contract. Similarly, even where a government is responsible for a breach of export commitments, this may result in disputes as to who under the contract should bear the loss. Again, this sort of private law matter, which in effect turns on the question of contractual intent, is not a major focus of this section.

Essentially there are two possible areas of law that may affect the ability of government to curtail electricity exports: constitutional law and international law. Of these, the more significant constraints would seem to exist in the constitutional arena. Accordingly, the bulk of the discussion presented below will focus on constitutional questions, both on the ability of Canadian governments generally to curtail exports and on the division of powers between governments. The section on international law focusses primarily on the constraints placed on governments in general as a result of international obligations, although even here we will suggest possible distinctions between the respective capacities of the federal and provincial governments.

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*This Appendix was prepared by A. R. Lucas and J. O. Saunders, Canadian Institute of Resources Law, University of Calgary, Calgary, Alberta. This Appendix attempts to state the law as of June 15, 1982.

A.2 Constitutional Issues

This section begins with a discussion of the sources of constitutional authority affecting control over natural resource exports, with particular reference to the division of powers betwen federal and provincial governments under The Constitution Act, 1982.[1] This is followed by a discussion in somewhat more detail of the constitutional aspects of selected topics which may bear on the specific question of curtailment of electricity exports. Specifically we will examine constitutional aspects of:

- export control under the Constitution Act;
- regulation of international and interprovincial transmission facilities;
- the treaty-making power of the federal government;
- taxation of natural resources; and
- the recent amendments to the Constitution.

Finally, we will examine the broader question of whether there are restrictions generally on governmental repatriation of electricity in Canada (that is, apart from the question as to which level of government may have the authority). This is essentially a question of ascertaining the significance of possible "vested rights" in these resources.

A.2.1 Sources of Constitutional Authority

In a broad sense legislative authority of the federal government and the provincial governments, respectively, in relation to electrical generation has been defined by provisions of the Constitution Act and by the relevant interpretive case law.[2] Basically, provinces have the authority to regulate the development of generation and transmission facilities within their boundaries. This includes regulation of development and use of energy resources found within provincial boundaries including water, coal, and uranium. The federal government has constitutional authority to legislate in relation to electricity that is moved across provincial or international boundaries. Electrical transmission or generation facilities that extend across provincial or international boundaries are also subject to federal legislative jurisdiction.

Provincial authority is based mainly upon ownership of public lands and resources within provincial boundaries. This is guaranteed to the provinces by Part VIII of the Constitution Act.[3] In addition, provinces have exclusive authority to legislate in relation to "the management and sale of public lands"[4] (including energy resources), "property and civil rights in the province,"[5] "local works and undertakings,"[6] and "generally all matters of a local or private nature in the province."[7]

Federal regulatory authority in relation to electrical energy produced within provinces is based on a number of Constitution Act heads of legislative power. However, the main sources of federal authority are s.91(2), "the regulation of trade and commerce" and the regulation of "works and undertakings connecting...provinces or extending beyond the limits of the province."[8] Works, including electrical generation and transmission facilities, may under s.92(10)(c) be declared "works for the general advantage of Canada," and thereby be brought under federal regulatory authority. Exclusive federal legislative authority in relation to navigation and shipping[9] and sea coast and inland fisheries[10] may have a substantial effect on provincial authority to develop water power within the province.

In addition, under the general or "peace, order and good government" power,[11] federal authority extends to dealing with national emergencies including economic[12] and, arguably, energy crises.[13] The peace, order and good government power also permits federal regulation of matters that would otherwise be exclusively provincial, in circumstances where such matters acquire "national dimensions" or extend beyond the concern of a locality or province.[14] The case law has not clearly defined the limits of this national dimensions aspect of the peace, order and good government power. However, this power is a major basis for overall federal regulation of nuclear energy and nuclear facilities for electrical generation.[15] Nuclear facilities have also been declared works for the general advantage of Canada[16] under s.92(10)(c) of the Constitution Act. Judicial statements in the Supreme Court of Canada suggest that the peace, order and good government power may also be a basis for federal control of hydroelectric developments on interprovincial or international rivers.[17]

A.2.2 Electricity Export and Related Issues

Export

The federal government has legislative authority to regulate the export of electrical energy from Canada. This includes export regulation of electrical energy produced entirely within a province and dedicated to export markets. These federal regulatory powers assume development of generation facilities and proposals to export all or part of the energy generated. Federal authority does not extend to mandating development of provincial resources for electrical generation. Apart from conditions of national emergency,[18] this development decision is the exclusive prerogative of the provinces as owners of the energy resources within their boundaries.[19] The principal direct technique for exercise of this federal regulatory power is a system of licences and permits such as the existing export licence requirements under the National Energy Board Act.[20]

Federal export regulatory powers are based primarily on the Dominion's exclusive power in relation to the regulation of trade and commerce.[21] The decided cases deal mainly with regulation of the importation and exportation of agricultural products. There is one Supreme Court of Canada decision that confirms exclusive federal jurisdiction to regulate importation of oil products.[22] However, the principle is equally applicable to export regulation of petroleum and other energy resources such as electricity.

The remainder of the federal 'handle' on regulation of electricity export is derived from the s.92 exception in relation to interprovincial and international works or undertakings.[23] Thus, there is federal power to approve construction of that portion of transmission lines which crosses the international boundary and to approve the international transmission of electrical energy through these lines.

Legislative power to regulate electricity exports extends to the establishment of terms of export. This clearly comprises the setting of export prices.[24] It also comprises the power to attach conditions to export approvals, including the terms of export licences, and requirements designed to protect Canadian utilities and consumers. These latter requirements may include conditions under which export must be curtailed upon the occurrence of specified events.[25]

Apart from ownership-based powers to determine whether or not energy resources should be exploited, it is unlikely that provinces have constitutional authority to regulate the export of electrical energy either to another province or to the United States. On one occasion, Ontario's highest court upheld provincial legislation under which upgrading requirement conditions could be attached to licences for timber export.[26] This power was held to be based on provincial ownership and the power to legislate in relation to the "management and sale" of public lands and resources.[27] But the case stands alone. There was no conflicting federal legislation in place, and more recent Supreme Court of Canada cases dealing with agricultural products,[28] oil and gas,[29] and potash[30] suggest that given properly framed legislation, federal authority under the trade and commerce power is likely to be held exclusive. This is particularly the case when it comes to electrical energy, which can be characterized as a 'manufactured' commodity produced from the basic energy resources of coal, uranium, oil, natural gas or water power.[31]

It is possible that both federal and provincial export legislation will be upheld as laws for constitutionally valid federal and provincial purposes, respectively. The provincial law may be characterized by a court as a matter of resource management and ownership prerogative, while the federal law may be held to be aimed at the regulation of trade and commerce. In this event, if the two statutes are found to be in operational conflict, then under the doctrine of paramountcy[32] the federal law prevails, and the provincial law is inoperative to the extent of the conflict.

International and Interprovincial Transmission Facilities

The otherwise clear federal power to regulate interprovincial or international electrical transmission facilities as works or undertakings connecting provinces or extending beyond provincial boundaries has been qualified by a recent Supreme Court of Canada decision. In Fulton v. Alberta Energy Resources Conservation Board,[33] it was held that the province, through its regulatory agency, retained constitutional authority to approve a 500-kV TransAlta Utilities Ltd. transmission line built to the British Columbia boundary and intended to interconnect with the B.C. Hydro system. Among other purposes, the line was intended to facilitate the export of power ultimately destined for United States utilities. However, no export application had yet been filed with the federal National Energy Board.

It was argued by the landowner plaintiffs that only the federal government had legislative authority to approve such an undertaking, since both interprovincial connection and the export of electricity through the line were contemplated. Had the plaintiffs been successful, TransAlta would have been unable to expropriate land for the transmission line right of way, since federal legislation does not include such expropriation powers. Pending enactments of amendments now before Parliament, the National Energy Board Act deals only with licensing power exports and approving international power lines.

The court held that the province had jurisdiction to regulate electrical transmission facilities that were wholly within its boundaries.[34] That the transmission facilities were intended to be connected with those of an agency outside the province did not bring the matter within exclusive federal authority. The provincial legislation was valid so long as it did not purport to regulate the interconnection. It was a matter within provincial authority in relation to local works and undertakings under s.92(10). The situation was particularly clear in the absence of federal legislation to regulate interprovincial power lines. Had such legislation existed, it is possible that a direct conflict with the provincial legislation could have been found that would have given the federal government jurisdiction on the basis of paramountcy.

There are implications in Chief Justice Laskin's judgment that the result might have been different had the proposed transmission line interconnected with a line owned and operated by the same utility in another jurisdiction.[35] This would be consistent with cases that have found operations such as railways[36] and motor transportation systems[37] to be single interprovincial or international undertakings and therefore subject to federal jurisdiction under s.92(10)(a). This part of the Supreme Court's opinion suggests that interconnected transmission facilities spanning several provinces and U.S. jurisdictions are not likely to be characterized as single works or undertakings. Systems are put together by provincial utilities constructing system components within provincial boundaries. This fact is likely to exclude full federal regulatory control of energy development and facilities construction for interconnected systems developed through coordinated planning.[38]

Following Fulton, the answer to the question of which level of government has constitutional authority to regulate electricity export facilities is somewhat ambiguous. It appears that provinces may authorize transmission lines within their boundaries that are intended to serve export purposes. Federal approval for interconnection and export volumes must ultimately be obtained. But construction of facilities may present federal authorities with a fait accompli that must, as a matter of federal-provincial relations, be accepted barring some significant national concern. This situation also presents a danger to potential electricity exporters. The problem involves uncertainty of regulatory requirements and the maintenance of good regulatory and political relations. Does a utility initially apply only to provincial agencies for the approval of facilities? Or does it also make export applications to the federal National Energy Board, even though, as a matter of corporate planning, such a move may be premature?

Proposed amendments to the National Energy Board Act[39] go some way toward remedying the problem. These amendments would allow the National Energy Board to approve expropriation of rights of way for international and interprovincial transmission lines. Following study by the Commons Committee on Energy Legislation, the proposed effective date of this legislation was delayed six months. The purpose was to give the governments of Quebec and Newfoundland additional time to reach an agreement on the transmission of Labrador hydro power through Quebec to the United States.

As it now stands, the National Energy Board is given jurisdiction to certify interprovincial power lines. Powers to expropriate necessary rights of way are vested in proponent utilities. Flexibility is provided by a power in the federal cabinet to designate proposed interprovincial power lines as lines to which these federal regulatory requirements apply. However, it seems clear that where a line is designated, a utility is not free of provincial requirements. It would still be obliged to apply to provincial agencies. There would inevitably be overlapping information requirements and regulatory hearings. But the Fulton case suggests that some measure of provincial regulatory jurisdiction in relation to such lines would be upheld.

Treaties

The power to enter into international treaties concerning electrical power export or hydroelectric development rests with the federal government. This authority is based on the historic power of the executive, along with the fact that Canada, and not its provinces, is the entity which is recognized in international law. Federal powers concerning national defence and "peace, order and good government" are also relevant. It has been suggested that provinces have some constitutional role in treaty-making.[40] But any provincial treaty role must ultimately be subordinate to that of the Dominion.

Federal treaty power does not include unlimited constitutional authority to implement obligations incurred under treaties. Before Canada achieved full independent status within the Commonwealth, the federal government had broad authority under s.132 of the British

North America Act (now the Constitution Act) to implement British Empire Treaties. But federal treaty implementation powers are now constrained by the legislative and public property ownership powers granted exclusively to the provinces. Thus the Privy Council held that the Dominion lacked power to enact legislation to implement international labour conventions to which Canada was a signatory.[41] Labour relations was determined to be a matter of property and civil rights for the provinces under s.92(13) of the Constitution Act.

Similarly, it was necessary for the federal government to negotiate with British Columbia concerning implementation of the Columbia River Treaty. As a matter of resource ownership, local works and undertakings, and property and civil rights in the province, British Columbia retained regulatory authority over the construction of dams and other facilities mentioned in the treaty.

Thus federally negotiated treaties concerning such matters as electricity export and hydroelectric development of international waters will not in themselves remove all obstacles to such proposed developments. Federal and provincial implementing legislation is required. Enactment of such legislation may be delayed by national political considerations that have little to do with the projects in question. But more important, developments within provinces are subject to provincial regulation, notwithstanding any federally negotiated treaties. Federal-provincial agreement may thus be necessary in any event. The difficulty that may be involved in reaching such agreement is graphically illustrated by the recent federal-provincial negotiations on oil and gas pricing and revenue-sharing.

Taxation

Taxation is likely to be an important consideration in planning electricity exports. Not only can taxation determine the initial viability of export projects, but also tax adjustments made with a view to prices of alternative U.S. domestic resources can effectively control the level of export.

The federal government is empowered by s.91(3) of the Constitution Act to enact legislation for "the raising of money by any mode or system of taxation." Provincial taxing power is limited to "direct taxation within the province"[42] except to the extent that taxes fall within the resources amendment in the new Canadian Constitution that is discussed in the next section. Considerable conceptual difficulty surrounds the question of whether a particular tax is direct, and therefore available to provinces. Courts do not attempt to determine the incidence of the tax by means of statistical evidence and expert advice of economists. Rather they consider the "general tendency" of the tax.[43] Certain taxes such as property and income taxes have traditionally been considered to be direct. Other taxes such as customs, excise and commodity taxes have been taken to be indirect.

Taxes levied on resources destined for sale outside producer provinces have been characterized as export taxes and therefore indirect. A Saskatchewan 'mineral income tax' levied on oil that was exported from the province to the extent of 98 percent was held to be an export tax and therefore indirect and ultra vires the province.[44] An oil royalty surcharge was also held invalid as an indirect export tax.[45] The Court concluded that the latter was not a true royalty, but rather a tax imposed above and beyond the sum representing a share of production taken by the province as resource owner.

However, a recent decision of the Alberta Court of Appeal suggests that federal authority to levy export taxes on energy resources may be limited. In Reference Re Natural Gas and Gas Liquids Tax,[46] the court considered a reference based on a specific factual situation. The Province of Alberta contracted to drill a well on Crown land near the U.S. border. Natural gas production was obtained and arrangements were made by the province to transport the gas by pipeline for direct sale to a purchaser in the United States. The province argued that the Federal Natural Gas and Gas Liquids tax, which purported to extend to natural gas exporters, had no application to export sales by the province. Such export sales were immune from federal tax under s.125 of the Constitution Act because the natural gas remained the property of the province until it was sold to the U.S. purchaser. Section 125 provided:

> "No Lands or property belonging to Canada or any province shall be liable to taxation."

The Alberta position was upheld by the Court of Appeal. Federal arguments that the tax was really on the sale transaction or the person involved, rather than on the provincial property in the gas, were rejected. The Court held that the statute in question was primarily aimed at raising revenue and could not be supported as regulatory legislation under the exclusive federal power in relation to regulation of trade and commerce.

An appeal by the federal government was dismissed by the Supreme Court of Canada.[47] The Court stated that the immunity conferred by s.125 had to override the express federal taxation powers. It was, said the Court,

> "...important for the survival of the provinces and of Canadian federalism that this vital source of provincial revenue be protected from erosion through taxation. Section 125 thus gives legislative recognition to that constitutional value..."[48]

The Reference has important implications for electricity export. First, it suggests that electrical energy developed by provinces through contractors or through non-arms-length Crown corporations[49] may be free of federal export taxes. A federal export tax could, however, be levied on electricity exported by investor-owned utilities, because the latter would not enjoy the protection of s.125. It is clear, however, that federal power to regulate exports by way of licences or other means extends to both provincial government and private utility-owned electricity.[50]

It is possible that the protection of s.125 may be lost because of the manufacturing step in which provincial resources - coal, natural gas, and water power - are converted into electricity. Arguably, the electricity produced is no longer provincial resource property, but merely a trade commodity exported by the government acting in a business capacity. However the Supreme Court of Canada explicitly rejected the argument that the application of "industry" by the province to find, develop and produce its natural gas resources prevented it from relying on s.125.

Constitutional Amendment

Sections 50 and 51 of The Constitution Act, 1982 deal with natural resources. The Act confirms exclusive provincial resource ownership powers. This includes exclusive provincial power to make laws in relation to:

> 92A(1)(c) "Development, conservation and management of sites and facilities in the province for the generation and production of electrical energy."

Provincial powers are extended to include regulation of resources exported from the province to another part of Canada. However, since laws of this type are expressly subject to conflicting federal legislation, the current position is little changed. Provinces are not empowered to regulate exports outside Canada. Thus even under the new

Constitution, the federal government has essentially exclusive power to directly regulate the export of electrical energy.

Another change enables provinces to levy indirect as well as direct taxes on "nonrenewable natural resources and the primary production therefrom" and "sites and facilities in the province for the generation of electrical energy and production therefrom." Consequently, under the amended Constitution, provinces as well as the federal government have power to impose taxes of general application that affect the export of electricity. However, to the extent that provincial taxes aim at things or activities other than sites and facilities for electricity generation or production therefrom, arguably including transportation of electricity, they must still be direct taxes within s.92(2). There is to be no discrimination in electricity site or facility and electricity production taxes between production used in province and production exported. The only other limits on either provincial or federal taxes are the necessity to provide electricity exporters with a return that will induce them to continue their activity.

The 'Legal Rights' heading of the Charter of Rights and Freedoms part of the Constitution Act includes rights to life, liberty and security of persons and their right not to be deprived of such rights "except in accordance with the principles of fundamental justice." There is no property rights protection analogous to that in the United States Constitution which makes the right to compensation explicit where property interests are expropriated or otherwise taken.

A.2.3 Vested Rights

In this section the following questions are examined:

(1) Are there any domestic law restrictions (apart from constitutional jurisidiction which merely goes to which level of government may act) on government repatriation of export electricity?

(2) If government can lawfully act to restrict or curtail electricity exports, do rights to compensation arise in those affected?

The analysis developed by Rowland J. Harrison[51] in relation to oil and gas licences, permits and leases is largely applicable. Harrison concluded that acquired or vested rights arising from oil and gas interests could be interfered with by the Legislature. This is based on the Supreme Court of Canada's decision in Spooner Oil Ltd. v. Turner Valley Gas Conservation,[52] which upheld regulatory changes introduced by the Crown that modified the terms of previously granted oil and gas leases. The same principle applies to other resource interests such as coal and water rights that may be used to generate electricity for export. Similarly, government may, by enacting legislation or by acting under previously enacted regulatory powers, curtail electrical export directly. The latter case is even clearer than the former, since no property or contractual interest is granted under regulatory approvals such as National Energy Board export licences.

Possible Curtailment Constraints

This government authority to curtail contracted and previously licensed electricity exports by legislative enactment is subject to two possible constraints, one legal, the other political. The legal constraint is that there is a presumption against legislative intention to impose by legal prescription restrictions on existing proprietary or contractual rights. Even though no contractual rights vis a vis government arise from export licences, the presumption may operate because private contractual rights under supply contracts are adversely affected. In the Spooner Oils Case the principle was stated as follows:

> The appropriate rule of construction has been formulated and applied many times. A legislative enactment is not to be read as prejudicially affecting accrued rights, or an "existing status" (Mann v. Stark (1890), 15 App. Cas. 384, at p. 388) unless the language in which it is expressed requires such a construction. The rule is described by Coke as a "law of Parliament" (2 Co. Inst. p. 292), meaning, no doubt, that it is a rule based on the practice of Parliament; the underlying assumption being that, when Parliament intends prejudicially to affect such rights or such status that intention is plainly manifested by unavoidable inference.[53]

What this comes down to is that legislation cannot change private rights retroactively unless it is drafted to apply to those rights expressly or by clear and unavoidable implication.

But no new legislation is necessary to curtail electricity exports. This may be done under pre-existing federal legislation, namely the National Energy Board Act. Curtailment may be achieved under conditions written into export licences by the NEB, as in the case of authorized interruptible electricity exports. It is not Board policy to make firm electricity exports subject to curtailment conditions. However, licences may be conditioned to require that firm export power be offered annually to interconnected Canadian electrical systems.[54] Export licences have included conditions requiring export of miscellaneous firm power (i.e., blocks of firm power for varying periods under contracts to be negotiated and individually approved by the Board) be interrupted if in the Board's opinion unforeseen circumstances cause interruption in the supply of guaranteed power to consumers in accessible Canadian markets.[55] Powers exist in the NEB Act to enable the Board to take steps to revoke or suspend licences provided the licensee is given an opportunity to be heard and subject to Cabinet approval.[56] Thus, even licences for firm electricity export are granted subject to pre-existing curtailment powers. Exercise of the power would not be characterized as retroactive, and in any event the curtailment power is so clear in the legislation that the presumption does not come into play.

An amendment to the National Energy Board Act[57] made as part of the 1982 "Energy Security Package" empowers the Board, with Cabinet approval, to revoke or suspend energy export licences if:

> "in the opinion of the Board the public convenience and necessity so requires."

Previously this section of the NEB Act stated only that licences could be suspended or revoked if any licence term or condition was not complied with or was violated.[58] However, electricity export licences were excluded from application of this proposed public convenience and necessity power by the Commons Committee on Energy Legislation[59] following electrical industry representations, particularly by Hydro-Quebec. Hydro officials told the Committee that export contracts would be difficult to negotiate if the Board had such a sweeping and unconstrained power to suspend or revoke licences at any time.

The result is that electricity export licences may still be suspended or revoked by the Board for non compliance or contravention of terms or conditions. However, the events or circumstances under which this power may be exercised must be spelled out as terms or conditions of licences. A licence term that purported to authorize curtailment or suspension if required by the public convenience and necessity or public interest would very likely not be upheld. This would arguably not be a term or condition at all, but merely a reservation or postponement of the original decision to approve the licence. Precision and clarity in drafting licence conditions is thus important and is a matter that may become increasingly important in NEB export licence hearings.

The presumption against confiscation would be applicable if a province acted to prevent or curtail electricity export by purporting such as coal, oil and gas or water power. In this event, Harrison's analysis applies precisely. Only if the provincial Crown is in a position to act as owner under contractual rights arising from leases, rather than as legislator, is the presumption avoided. Precise confiscatory legislation could of course be drafted. But the political price in terms of industry relations and investor preceptions would be heavy.

Newfoundland's legal action to "recall" 800 megawatts of Churchill Falls power for its own use arises out of very special circumstances. The issue is whether the water lease to Churchill Falls-Labrador Corp. (CFLCo), as confirmed by a Newfoundland statute, and the terms of the electricity sale agreement between CFLCo and Hydro-Quebec permit the province to take this relatively small amount of power out of the total amount contracted to Hydro-Quebec. The matter has been pending before the Newfoundland courts since 1976.

When the provincial government concluded that further negotiation with Hydro-Quebec would be futile, it passed an act[60] to revoke the water rights previously granted to CFLCo and to vest CFLCo generating facilities in the provincial Crown. However, the Act was not proclaimed, and was by its own terms referred to the Newfoundland Court of Appeal to test its validity. Provision was made in the Act for payment of all indebtedness secured by way of mortgage, lien, debenture or other encumbrance on the property in question. Shareholders of CFLCo were to be compensated for any reduction in the value of their shares as a result of the coming into force of the Act. However, all other actions were specifically barred.

The Newfoundland Court of Appeal in a unanimous decision on the Reference[61] held that the Act is valid provincial legislation in relation to provincial property and civil rights in the province. Arguments that the Act is invalid as affecting civil rights outside the province, as pertaining to interprovincial trade in electricity, as 'sterilizing' a federally incorporated company, and as relating to interprovincial works or undertakings were all rejected.

The court agreed that civil rights outside the province, particularly Hydro-Quebec's rights under the power contract and the rights of bondholders and other secured creditors of CFLCo, were affected by the Act. However, these effects are merely collateral, and necessarily incidental, to the clear purpose of the Act - to legislate in relation to the ownership, control and management of a natural resource located wholly within the province.

Nor does the Act aim at regulating interprovincial trade in electricity. The court noted that there was no attempt to regulate the price of electricity to be exported from the province. Ownership of a provincial natural resource is the essence of the Act. It is irrelevant that almost all power generated from that natural resource is exported. Consequently, there is no infringement of the federal trade and commerce power.

CFLCo, as a federally incorporated company, is not sterilized in its essential functions and activities. Its essential corporate capacities, such as its power to raise capital by issuing shares or debentures, are not affected. The court followed the recent Quebec Court of Appeal decision upholding Quebec's expropriation of Asbestos Corporation.[62] It is true that CFLCo's property is taken, and that the Act is not of general application. But these latter points cannot overturn the well established provincial power in relation to expropriating private property for public purposes. A federally incorporated company has no more privileges than a provincial company or a natural person.

The final argument against the Act centered on the fact that it was legislation in relation to an interprovincial work or undertaking contrary to section 92(10)(a). This was rejected. The Court applied the Supreme Court of Canada's decision in the Fulton case.

However, it should be noted that the Newfoundland Court of Appeal's decision is being appealed to the Supreme Court of Canada.

Provinces could prevent construction of export-dedicated generation facilities by acting through regulatory agencies under existing legislation. In Alberta for example, Cabinet approval could simply be withheld under the Hydro and Electric Energy Act[63] on any Energy Resources Conservation Board recommendation for approval of a thermal generating station. However, provinces would be constitutionally barred from using facility approval regulatory powers to curtail exports either by direct order or by action under plant operating licence conditions. This would be an intrusion into export regulation, a field exclusively within federal jurisdiction under the trade and commerce power. It is possible that provincial curtailment could be achieved by enforcement of environmental or health regulations against a generating station. But this action must be based on some cogent evidence. Provincial use of environmental or health regulations as a subterfuge to curtail electricity export would be struck down as a 'colourable' attempt to invade the exclusive federal field of export regulation.

Generally, the political constraint is significant, though not readily quantifiable. Provinces could be penalized by lower international credit ratings that would make it difficult to place bonds and otherwise to borrow outside Canada. Apart from any lack of constitutional power as suggested above, this would be a strong constraint on implementation of recent Quebec government threats to curtail electricity exports to United States utilities if steps are not taken to reduce sources of acid precipitation.

From a federal standpoint there is a political cost involved in regulatory actions that penalize an industry, particularly an industry that is essentially an agency of provincial government as is the case of the electrical power industry in most provinces, including Quebec. In particular, the stature of Hydro-Quebec, the significance of electrical energy in Quebec's energy future, and the sensitivity of related economic and cultural issues would make federal electricity export curtailment a charged issue in federal-Quebec relations.

International relations considerations form a second set of political constraints. The possibility of U.S. retaliation in energy or in other trade areas would have to be seriously weighed. However, curtailment action, even in the face of U.S. opposition, must be considered possible. This is shown by the essentially uncompromising implementation of the federal National Energy Program in the face of retaliation proposals by a number of U.S. legislators.

Possible Implied Right to Compensation

There is Canadian authority, including one Supreme Court of Canada decision,[64] for the proposition that there is an implied right to compensation for a deprivation of 'property' by government action. 'Property' appears to include contractual rights and even the goodwill of a business.

However, this right would not apply to the curtailment of electricity exports by government action under regulatory legislation. The reason is that the regulatory instrument, in this case the NEB export licence, confers no property or contractual rights. It is merely a regulatory permission that creates no private vested rights. Any electricity exporter proceeds subject to pre-existing legislative curtailment powers. Curtailment in these circumstances is not a retroactive legislative act. It is not confiscation, despite the obvious business impact.

In any event, as Harrison[65] points out, the implied right to compensation is subject to the ultimate supremacy of Parliament. Legislation can be enacted that specifies that no compensation, or only clearly stated partial compensation, shall be paid as a result of particular confiscatory acts. The inevitable political price would, of course, be paid. Newfoundland's Upper Churchill Water Rights Reversion Act is an example.

A.3 International Law Issues

Canada's obligations under international law may be broadly considered as fitting into two categories: 1) those arising as a result of specific treaty obligations; and 2) those arising as a result of the operation of general principles of international law. Depending upon whether or not they have been incorporated into legislation (national or provincial), these obligations may or may not be enforceable in this way, although the claims may of course be pressed on a government-to-government basis and in some cases through international tribunals. Instances might also arise when these obligations could be enforced in courts in foreign jurisdictions.

This section will outline briefly Canada's position at international law in the event of curtailment of energy exports by Canada, assuming that - as is now, with some arguable exceptions, the case - no specific treaty obligations exist. We will then suggest the extent to which this situation might be changed if treaties guaranteeing these exports could be concluded. Some comments will also be offered on the practical problems of securing redress where international law has been breached.

A.3.1 The Existing Situation

Although a reduction in electricity exports by Canada could come about in number of ways, the interesting scenario for our purposes, and the one which is assumed here, is a situation involving government curtailment of firm power exports where NEB licences have already been granted. (This is other than the cases, of course, where licences are revoked or suspended as a result of non-compliance with some condition or term, as provided for in s.84 of the National Energy Board Act.) We will also assume, keeping in mind our earlier comments regarding vested rights, that this termination has been accomplished in such a way that redress is not available through Canadian courts.

Canada does maintain general commitments to free trade, both in various bilateral agreements and also multilaterally under the General Agreement on Tariffs and Trade (Gatt) and the Organization for the Economic Cooperation and Development (OECD). Realistically though, such general provisions are unlikely to provide the basis for an international claim against Canada in the circumstances that we are considering. In the absence of treaty obligations, what are the relevant principles at international law that govern the arbitrary cancellation of such export permits? The major questions of interest would seem to center on, first, whether such a cancellation would constitute an expropriation at international law and, second, whether an expropriation of this nature conforms to certain norms regarding compensation.

As to the first question, it is by no means clear that mere cancellation of an export permit would constitute an expropriation for purposes of international law, where there must at least be some taking of property involving a foreign owner. Assuming that it is the domestic utility which both owns the power and has been granted the export permit, it seems difficult to construe such an action as expropriation of foreign property. Certainly revocation of the licence may result in a situation where the Canadian producer cannot fulfill certain obligations under his contract with the American consumer. But while this raises private law questions relating to such matters as, for example, the interpretation of force majeure clauses, it does not of itself give rise to a situation involving breach of international obligations.

The question of expropriation may, however, arise where foreign utilities have themselves taken some direct involvement in the production of the power. Obviously the larger and more direct the stake by foreign utilities in such production, the more likely the government action may be characterized as an expropriation that is subject to international law. However, even assuming that an American utility has a direct stake in the production of electricity being exported, cancellation of an export permit may still not amount to an expropriation. Suppose for example, and this would seem likely to be the case, that Canadian markets for the electricity existed. Arguably, then, the foreign utility has suffered no loss qua producer. There has simply occurred a change in customers.

Perhaps an even more telling argument against the proposition that termination of a licence amounts to expropriation is the existence of s.17 in the National Energy Board Act, which allows the Board to review, alter or rescind any order issued by it, subject to the approval of the Governor in Council. There is certainly a strong argument that this provision effectively destroys any notion that such a licence creates a property right which may not be 'expropriated' at international law.

Even if we assume the strongest case for the American producer, namely that a cancellation of an export licence does in fact constitute an expropriation at international law, it still does not follow that such a taking is unlawful per se. Apart from those special exceptions where expropriation is lawful even without compensation,[66] an international claim may be resisted on the basis that in fact there has been prompt, adequate and effective compensation. The question of what constitutes appropriate compensation in international law is a thorny one, and depends very much on the facts of each particular case.[67] Moreover, monetary compensation may not entirely resolve the problem for the American utility, which may well be primarily interested in the problem of assuring security of supply.

The New Brunswick-Maine Dispute

An interesting example of an American utility's reaction to an action by the Canadian government which effectively changes the nature of a contract with a Canadian supplier is provided by the recent dispute between certain New England utilities and the New Brunswick Electric Power Commission (NBEPC). The case arose out of the change in the Petroleum Import Cost Compensation Regulations[68] which resulted from the rapid escalation of world oil prices in 1979 - 1980.

Until 1980, the federal compensation provisions, which in effect subsidized the cost of imported oil, provided compensation for oil used in the generation of electricity, regardless of whether that electricity was used for domestic or export purposes.[69] Under an agreement between NBEPC and the Maine Electric Power Company (MEPCO), NBEPC had agreed to provide varying amounts of electricity from three oil-fired generating units at Coleson Cove, New Brunswick over a ten-year period. It was as a result of this agreement, which included provisions for substantial capital expenditures by MEPCO, that the Coleson Cove project went ahead. Part of the agreement provided for apportionment of fuel costs in accordance with the share of energy taken from the unit. An earlier attempt in 1976 by NBEPC to charge higher fuel prices for electricity exports had been resolved when it became apparent that this discrimination would not be necessary under the Compensation Regulations. It was agreed as a result of that dispute that any future discrimination by NBEPC towards its U.S. customers would require 60 days notice.

In June 1980, as the level of compensation had grown substantially with the rise in world oil prices, the federal government indicated its intention, beginning September 1980, to phase out the subsidy with respect to that portion of oil used to generate export-dedicated electricity. The appropriate notice was given to MEPCO by NBEPC, with increased prices (reflecting the higher, non-subsidized fuel costs for electricity exports) scheduled to begin in September of that year.

In the result, MEPCO and other associated New England utilities sued in the United States[70] for a declaration that MEPCO could treat the agreement as terminated. The lawsuit is interesting for our purposes in two respects: (1) the grounds on which relief was sought and 2) its ultimate resolution.

It is significant that the action was framed on a number of grounds, but all of which go to the question of contractual intent. Thus the amendment to the Canadian regulations was of interest only insofar as it raised the question as to whether this in some sense vitiated the (arguable) underlying assumption of Canadian approval to the agreement.[71] No question seems to have been raised of the propriety of the Canadian action (which admittedly may reflect the fact that it was in substance probably hard to attack). Similarly, the other grounds argued, essentially fundamental breach and repudiation, were very much matters of private contractual law.

This traditional contractual approach flows from the nature of the participation agreement between the parties. That is, the whole matter is treated as one involving private obligations and not one that contemplates public law intrusion. (It is interesting that the agreement lacks even a standard force majeure clause although MEPCO does include such a clause in its separate agreement to transmit power to the other utilities involved.[72])

The ultimate solution is also of interest. Eventually a compromise centering on the amount of power MEPCO would be required to purchase was reached and the matter was settled out of court (although NBEPC indicated it would have been willing, if necessary, to go to trial on the matter). NBEPC personnel stressed their desire to reach a solution satisfactory to all parties concerned. This illustrates the concern of suppliers to maintain good 'customer relations' in a situation where these utilities might constitute a market for future electricity sales.

Another aspect of some interest in this case is the agreement by the federal government at the time to reimburse NBEPC for any loss incurred as a result of MEPCO's reduced financial commitment to the project arising out of the reduction in its power entitlement. This action, which would not appear to have been legally required, seems indicative of a concern by the federal government to preserve some equity in a situation where unanticipated government action had significantly affected the benefits flowing from a private international contact.

The NBEPC-MEPCO dispute is of course different from the case of export interruption that we have posited, in that it involved a U.S. utility wanting an agreement terminated due to a price rise. The important point remains, however, that such purchase agreements are treated essentially as giving rise to private obligations. Thus, where such contracts are affected or even frustrated by government action, the normal response will be through private law channels with which the parties are more familiar and comfortable - whether invocation of force majeure clauses, resort to private arbitration or use of other normal contractual remedies. In practice, then, it is unlikely that an individual company would pursue theoretical avenues of redress at international law.

A.3.2 Electricity Exports Guaranteed by Treaty

The use of treaties to regulate the flow of natural resources has apparently had some success in Europe. However, we are not entirely hopeful that the European experience is one that can be readily translated to North America. At the very least it must be noted that the politics of the situation make it highly unlikely that Canada would commit itself by treaty to any restrictions on its ability to control the export of electricity. In any event, even a treaty will probably not solve the problem of curtailing exports in times of national emergency. What constitutes a national emergency is of course a matter of interpretation, and it may be that the Canadian government would choose a very elastic interpretation.

A.3.3 Enforcement

Assuming some breach of international obligations can be found in the curtailment of export licences, a number of avenues are open for achieving redress. Realistically, however, not all of these can be considered viable options for an individual electric utility.

Beginning with the most unlikely route, the United States government could press a claim before the International Court of Justice. This typically would involve a great deal of time and expense, and the relief would be limited - the Court could only issue a declaration of its view of the matter. While Canada would very likely feel bound by such a finding, the major effort involved in pressing the claim in this manner, when balanced against the relative insignificance of the issue, makes the possibility of an action before the Court only a theoretical one. This is reflected in the practice of states generally, where even major expropriation cases (i.e., involving whole sectors of an economy) are heard in different form, often through arbitration tribunals or claims commissions. In sum, the use of the Court by states is normally restricted to cases raising significant issues of public international law.

An arbitration tribunal is a somewhat more appropriate vehicle for dealing with the sort of situation we have envisaged. Such a tribunal is often used to resolve major claims arising out of expropriation, although it is not a method that has generally found favour in Canadian-American relations, where negotiation and compromise have been preferred. Moreover, the initiation of such a procedure involves the consent of both states. Given our earlier comments on the doubtfulness of the confiscatory nature of a licence revocation, it is somewhat questionable whether Canada would agree that any claim existed to be arbitrated.

There is a possibility that an action could be maintained by the utility affected in an American court. This method was attempted, for example, following expropriations by the Castro government in Cuba.[73] However, the approach presents significant obstacles to the American utility. First, it may be objected, on the basis of sovereign immunity, that the Crown may not be impleaded before a foreign court. Given the United States adoption of a 'restrictive' theory of immunity - which allows for both the initiation of suits and the attachment of assets when a state is acting in effect as a commercial entity[74] - it is unlikely that this exception to the general rule would be extended to give immunity to Crown corporations producing electricity.

A second objection to the assertion of jurisdiction by the United States courts arises from the 'act of state' doctrine, which precludes United States courts from questioning the validity of the public acts of a foreign state taken within its own jurisdiction. Since the particular formulation of the doctrine with respect to expropriation in the Sabbatino case,[75] this inclination towards judicial self-restraint has come under attack and to some extent has been modified as the result of legislation by Congress.[76] Nevertheless, the better view is probably that Canadian efforts to repatriate electricity exports would be protected from attack in the United States courts, especially since any hypothetical interference with existing rights would be with contractual rather than property rights.[77]

In sum, the scope for employing formal legal channels when pressing a claim at international law, while theoretically fairly broad, is in reality not all that great for the specific situations which are likely to arise in connection with the curtailment of electricity exports.

This, in effect, leaves the option of negotiation and compromise, which is typically the route such matters take in Canadian-American relations. To some extent, this avenue has been discussed earlier with respect to vested rights. It is probably not useful to expand upon this option here. However, it may be worth noting the significance here of a treaty 'guaranteeing' in some way electricity exports. Certainly the existence of such treaty provisions would make it politically very difficult to curtail such exports. It would also, of course, improve significantly the United States case if it chose to pursue an international claim through the other avenues suggested earlier.

One other aspect of some interest with respect to enforcement of international law arises from the nature of Canada's federal system. This concerns the question of whether provinces have the legal capacity domestically to act in contravention of international law. It has been suggested earlier that provincial attempts to regulate exports of natural resources might well be struck down as violating the division of powers under The Constitution Act. Even assuming that in some cases these attempts may be allowable as directed towards control of natural resources, the constitutionality of curtailing exports may face an obstacle on other grounds if the attempt to halt exports is also in violation of international law.

The ability of the federal government to legislate in contravention of international law is probably not now in question.[78] However it is far more questionable whether the provinces have this ability. Thus, in the Foreign Legations case,[79] an attempt by the City of Ottawa to levy taxes on foreign legations, pursuant to an

Ontario statute authorizing municipalities to set and collect property taxes, was struck down by the Supreme Court of Canada. The majority judgment found that such an assessment would be in violation of international law and that the overriding statute should not be construed so as to imply the delegation of this sort of power of assessment. However, at least two of the three majority judges[80] seemed to take a broader view and questioned the very right of the province to enact any such assessment, in light of the contravention of international law that would follow.

One underlying rationale for this limitation on provincial powers is the doctrine of extra-territoriality, originally developed as a means of restricting colonial legislation within certain bounds and thus of preventing conflict with imperial practice in the international area. It has been suggested by analogy that provincial governments similarly lack competence to legislate in contravention of international law.[81] Moreover, this view is arguably consistent with the nature of the federal state, where, for example, the federal government would be held accountable in international law as a result of breaches by a provincial government. Again, however, the practical significance of this argument should not be overestimated. It can be expected that courts would be very reluctant to interpret domestic legislation as contravening international law. Moreover, much stronger constitutional objections to provincial intrusion into export matters have been suggested earlier.

A.4 Conclusions

Given the Canadian federal system, initiatives to curtail electricity exports can come from either the federal government or provincial governments. Consequently, the question of which level of government has constitutional authority to legislate in relation to electrical generation stations, transmission of electricity, and electricity export regulation becomes important. Generally, the federal government's jurisdiction to levy tax and to regulate prices, interprovincial and international transmission facilities, and electricity export give it greater export curtailment powers. Provinces are largely limited to restricting or preventing the development of resources to be used in the generation of electricity for export. They have powers related to the approval of facilities, including transmission lines within provinces, that may be used to thwart potential export schemes. But once export facilities are constructed and placed in operation, provincial governments lack constitutional power to curtail directly electricity exports. This constitutional picture is essentially unchanged under the new Constitution.

Since electricity exports are subject to regulatory approval under pre-existing legislation which permits inclusion of curtailment or interruption conditions in licences, exporters have no rights of legal action to prevent export curtailment by government. Nor are there implied rights to compensation. Such rights arise only from contractual or property interests conferred by government grants of resource rights that are of a higher order than a mere regulatory permission.

However, a lengthy history of Canada-U.S. cooperation in electricity exports exists. No licence for export of electricity has ever been revoked by the National Energy Board. The recent committee amendment to the National Energy Board amending act to exclude electricity export licences from the Board's power to revoke or suspend energy licences, where the Board is of the opinion that the public convenience and necessity so requires, is an example of Canadian government sensitivity to the need to maintain this cooperation.

Although Canada maintains general commitments to free trade pursuant to participation in the Gatt and OECD, treaties directed at securing exports of electricity to the United States do not exist. In the absence of such specific arrangements, any major objections under international law to Canadian curtailment of such exports must be founded on broad principles dealing with expropriation and compensation. On these grounds it would be difficult to challenge cancellation of export licences by the Canadian government. It is questionable whether such cancellations would be characterized as expropriations at all, let alone expropriation of foreign property. This conclusion is strengthened by the broad powers to rescind or amend licences reserved under the National Energy Board Act. Furthermore, even characterizing the situation as one of expropriation, it is by no means clear what would be regarded as appropriate compensation. Obviously, to the extent that exports were guaranteed by treaty, the position of consuming utilities in the United States would be greatly improved.

Even assuming that a breach of international obligations can be argued, the enforcement of rights at international law is also problematic. An action before the International Court of Justice is highly unrealistic, and international arbitration only slightly less so. Similarly, while action against Canada in an American court is a theoretical possibility, in fact significant and probably insurmountable obstacles would face the applicant, most notably the doctrine of 'act of state'. In the result, negotiation and compromise between the governments involved seems the most probable route of pressing such international claims. In general though, utilities affected by such changes of policy are more likely to react by pursuing their private contractual remedies, possibly by invoking *force majeure* clauses or *private* arbitration proceedings.

Footnotes

[1] As a result of the 1981 - 82 constitutional amendment process, this act has replaced *The British North American Act*.

[2] For a detailed discussion see L. Barry, "Interprovincial Electrical Energy Transfers; The Constitutional Background," in P. Nemetz (ed.) *Energy Crisis: Policy Response* (Montreal: Institute for Research on Public Policy, 1981).

[3] Particularly s.109 which provides that provinces own public lands within their respective boundaries. The effect of s.109 was extended to the western provinces by the National Resource Transfer Agreements and The B.N.A. Act, 1930.

[4] *The Constitution Act*, s.92(5). [Hereinafter Constitution Act]

[5] Constitution Act, s.92(13).

[6] Constitution Act, s.92(10).

[7] Constitution Act, s.92(16).

[8] Constitution Act s.92(10)(a).

[9] Constitution Act, s.91(10).

[10] Constitution Act, s.91(12).

[11] Constitution Act, s.91, opening and concluding clauses.

[12] *Reference Re Anti-Inflation Act* (1976), 68 D.L.R. (3d) 452 (S.C.C.).

[13] H. Marx, "The Energy Crisis and the Emergency Power in Canada," (1975) 2 Dalhousie L.J. 446.

[14] See *A.-G. Ontario* v. *Canada Temperance Federation*, [1946] A.C. 193 (P.C).

[15] *Pronto Uranium Mines* v. *Ontario Labour Relations Board*, [1956] O.R. 862 (Ont.H.C.); *Denison Mines* v. *A.-G. Canada*, [1973] 1 O.R. 797 (Ont.H.C.).

[16] *Atomic Energy Control Act*, R.S.C. 1970, c.A-19, s.17.

[17] *Interprovincial Cooperatives and Dryden Chemicals Ltd.* v. *The Queen in Right of Manitoba*, [1976] 1 S.C.R. 477.

[18] See *Reference Re Anti Inflation Act*, *supra*, note 12.

[19] Under Part VIII, and s.92(5) of the Constitution Act.

[20] R.S.C. 1970, c.N-6 as amended, Part VI.

[21] Constitution Act, s.91(2).

[22] *Caloil Inc.* v. *A.-G Canada*, [1971] S.C.R. 543.

[23] Constitution Act, s.92(10)(a).

[24] *Central Canada Potash* v. *Government of Saskatchewan*, [1978] 6 W.W.R. 400 (S.C.C.).

[25] As an incident of the basic power to approve or disapprove proposed exports. See *National Energy Board Act*, s.82.

[26] *Smylie* v. *The Queen* (1900), 27 O.A.R. 172 (Ont.C.A.).

[27] Constitution Act, s.92(5).

[28] *Reference Re Farm Products Marketing Act*, [1957] S.C.R. 198.

[29] *Canadian Industrial Gas and Oil Co.* v. *A.G. Sask.* (*CIGOL Case*), [1977] 6 W.W.R. 607 (S.C.C.).

[30] *Central Canada Potash* v. *Government of Saskatchewan*, *supra*, note 24.

[31] And therefore not a matter of provincial public property within Part VIII and s.92(5) of the Constitution Act.

[32] See P. Hogg, *Constitutional Law of Canada* (Toronto: Carswell, 1977), pp. 101-113.

[33] *Fulton* v. *Energy Resources Conservation Board*, [1981] 4 W.W.R. 236 (S.C.C.).

[34] *Id.*, at 244-245, applying *Kootenay and Elk River Railway* v. *C.P.R.*, [1974] S.C.R. 955.

[35] *Id.*, at 243-244.

[36] *Luscar Collieries Ltd.* v. *McDonald*, [1927] A.C. 925 (P.C.).

[37] *A.-G. Ont.* v. *Winner*, [1954] A.C. 541 (P.C.).

[38] Barry, *supra* note 2 at 225. The author suggests, however, that coordinated planning combined with joint development of generating

and distribution systems and with joint financing may result in individual provincial networks being merged into an interprovincial network under federal jurisdiction.

[39] Bill C-108, National Energy Board Act Amendment, First reading, April 7, 1982, s.11 (repealing and substituting *National Energy Board Act*, ss.40 and 41); s.12 (amending *NEB Act*, *s.43*); and *s.30* (adding *NEB Act*, s.90.1 "Extension to Interprovincial Power Facilities").

[40] G. Morris, "The Treaty-Making Power: A Canadian Dilemma," (1967) 45 Can. Bar Rev. 478; Jacomy-Millette, *Treaty Law in Canada* 85-94 (1975).

[41] *A.-G. Can.* v. *A.-G. Ont.* (*The Labour Conventions Case*), [1937] A.*C. 326 (P.C.)*

[42] Constitution Act, s.92(2).

[43] *Bank of Toronto* v. *Lambe* (1887), 12 App.Cas. 575.

[44] *CIGOL Case*, *supra*, note 29.

[45] Following *A.-G. B.C.* v. *McDonald-Murphy Lumber Co.*, [1930] A.C. 357.

[46] *Reference Re Questions Set Out in O.C. 1079/80 Concerning Tax Proposed by Parliament of Canada on Exported Natural Gas*, [1981] 3 W.W.R. 408 (Alta.C.A.).

[47] *Reference Concerning a tax proposed by the Parliament of Canada on exported natural gas*, as yet unreported, June 23, 1981, majority reasons by Laskin C.J. and Martland, Ritchie, Dickson, Beetz, Estey and Chouinard, J.J. Dissenting reasons by McIntyre and Lamer, J.J., are to be delivered later.

[48] *Id.*, at p. 24.

[49] Where a Crown Corporation is given such independent powers that it ceases to be an extension of the Crown, it may lose the constitutional immunities of the Crown. See G. LaForest, *The Allocation of the Taxing Power Under the Canadian Constitution*, 154 (Toronto: Canadian Tax Foundation, 1967).

[50] Hogg, *supra*, note 32 at 179-180.

[51] R. Harrison, "The Legal Character of Petroleum Licences," (1980) 18 Can.Bar.Rev. 483.

[52] [1933] 4 D.L.R. 545.

[53] *Id.*, at 552.

[54] Canadian Niagara Power Company Limited, Export Application, National Energy Board, Reasons for Decision, February, 1981 at p. 9.

[55] NEB licence EL-96 issued to Hydro-Quebec. See Hydro-Quebec, Export Application, National Energy Board, Reasons For Decision, September 1976, at p. 54. A similar condition was rejected for an Ontario Hydro licence in National Energy Board, Reasons For Decision, May, 1981. A condition that the miscellaneous firm export could be interrupted if needed to supply Ontario loads was imposed on Ontario Hydro.

[56] *National Energy Board Act*, ss.17(2), 20(1), 84.

[57] Bill C-108, National Energy Board Act Amendment, *supra*, note 39, s.25, amending *National Energy Board Act*, s.84.

[58] National Energy Board Act, s.84.

[59] The Bill was reported back from the Committee with amendments June 3, 1982.

[60] *Upper Churchill Water Rights Revision Act*, S.Nfld, 1980, c.40.

[61] *Reference re Validity of Upper Churchill Water Rights Reversion Act, 1980,* Unreported, Newfoundland Court of Appeal, March 5, 1982, Mifflin, Morgan and Gushue, JJA.

[62] *Societe Asbestos Limitee* v. *Societe Nationale de l'Amiante*, [1981] C.A. 43 (QUE.).

[63] S.A., 1971, c.49, s.7 requires that a bill authorizing the Board's approval be introduced and passed by the Legislature.

[64] *Manitoba Fisheries Ltd.* v. *The Queen* (1978), 88 D.L.R. (3d) 462 (S.C.C.).

[65] *Supra*, note 51 at 494.

[66] Wartime defence measures and exercise of police powers are sometimes cited as examples. See Ian Brownlie, *Principles of Public International Law*, 2nd edition (Oxford: Clarendon Press, 1973), p. 523.

[67] The question of compensation is particularly difficult in cases involving major resource sectors in a country. See *id*., pp. 522-33.

[68] C.R.C., c.1262, pursuant to the *Petroleum Administration Act*, Stat. Can. 1974-75-76, c.47, s.77. The amendment is by SOR/80-727.

[69] More correctly, this was the case until February 1977 when the regulations were amended to remove compensation for oil used to generate electricity for export, with the specific exception of contracts entered into prior to February 1977. Since the dispute considered here was effectively 'grandfathered' by this exception, the amendments of interest here did not occur until 1980.

[70] See United States District Court for the District of Maine, Civil Action No. 80 0293 P.

[71] Relying on a clause in the agreement which specified:

"13(e) if as a direct consequence of Governmental action in Canada the Commission is prevented from making deliveries under this Agreement, the Company shall be at liberty to terminate this Agreement."

[72] Although clause 13(3) *id.* is in effect one element of a *force majeure* clause.

[73] Unsuccessfully, though, in the first instance. See *Banco Nacional de Cuba* v. *Sabbatino* (1964), 375 U.S. 398, 84 S.C. 923.

[74] See generally "Foreign Immunities Act of 1976," P.L. 94-583, 28 USC 1330.

[75] *Supra*, note 73.

[76] Most significantly by the Foreign Assistance Act of 1964, 22 U.S.C. 2370(e)(2) (Supp. I, 1965), as amended, Foreign Assistance Act of 1965, 22 U.S.C. 2370(e)(2) (Supp. V, 1969). This refers to the Second Hickenlooper Amendment, which attempted to cut down the scope of the act of state doctrine, particularly in cases involving foreign expropriation of property. The amendment has met with mixed success in its interpretation by the courts. See Note, "*Sabbatino* Comes Full Circle: A Reconsideration in Light of Recent *Decisions*" (1971), 4 N.Y.U. Journ. of I.L. 260.

[77] See on this point *French* v. *Banco Nacional de Cuba*, 23 N.Y. 2d 46, 242 N.E. 2d 704, 295 N.Y.S. 2d 433 (1968). For a more recent affirmation of the act of state doctrine, see *Hunt* v. *Mobil Oil Corp.*, 550 F. 2d 68 (2d Cir. 1977); certorari denied 434 U.S. 984 (1977).

[78] But for a dissenting view that questions the ability of even the federal government in this respect see Vanek, "Is International Law Part of the Law of Canada?" (1949-50), 8 U. of T. L.J. 251, pp. 265-67.

[79] Reference Re Tax on Foreign Legations, [1943] S.C.R. 208, [1943] 2 D.L.R. 481. The case is discussed at some length in La Forest, "May the Provinces Legislate in Violation of International Law?" (1961), 39 Can. Bar Rev. 78.

[80] Rinfret and Taschereau JJ. See LaForest, id., pp. 80-81.

[81] Id., pp. 81-87. For further discussion of possible provincial incompetence in this field see Rand, "Some Aspects of Canadian Constitutionalism" (1960), 38 Can. Bar. Rev. 135, pp. 143-44. For judicial support for the contrary proposition, namely that provinces can legislate contrary to international law, see the dicta of Meredith C.J.C.P. in R. v. Meikleham (1905), 11 O.L.R., 366, (Ont.Div.Ct.), at p. 373. Some support might also be derived implicitly from the Labour Conventions case, supra, note 41, discussed earlier.

APPENDIX B

ELECTRICITY EXPORTS IN PERSPECTIVE

TABLE B.1

CANADIAN ELECTRICITY EXPORTS AND IMPORTS TO THE UNITED STATES 1956-1981

Year	Total Net Canadian Generation[a] (GW·h)[b]	Exports to U.S.		Imports from U.S. (GW·h)	Net Exports to U.S.	
		Volume (GW·h)	% of Generation		Volume (GW·h)	% of Generation
1956	88 455	5 104	5.8	239	4 865	5.5
1961	113 713	4 157	3.7	1 394	2 763	2.4
1966	158 135	4 397	2.8	3 218	1 179	0.7
1971	216 472	6 969	3.2	3 378	3 591	1.7
1972	240 213	11 037	4.6	2 381	8 656	3.6
1973	263 335	12 286	4.7	2 249	10 037	3.8
1974	280 256	15 400	5.5	2 441	12 959	4.6
1975	273 392	11 409	4.2	3 972	7 437	2.7
1976	294 043	12 804	4.4	3 590	9 214	3.1
1977	317 196	19 957	6.3	1 690	18 267	5.8
1978	335 654	21 593	6.4	2 099	19 494	5.8
1979	352 304	31 378	8.9	1 792	29 586	8.4
1980	367 306	30 176	8.2	2 939	27 237	7.4
1981[c]	377 622	35 372	9.4	1 497	33 875	9.0

SOURCES: Canada, Department of Energy, Mines and Resources, Electric Power in Canada 1981 (Ottawa: Electrical Branch, 1982), Table 1. Canada, Statistics Canada, Electric Power Statistics, Catalogue 57-001 Monthly; Catalogue 57-202 Annual, Volume II, Table 17.

[a] Generation net of station service.

[b] Millions of kW.h.

[c] Preliminary figures.

TABLE B.2

GROSS PROVINCIAL UTILITY EXPORTS OF ELECTRICITY BY MAJOR FIRM AND INTERRUPTIBLE TYPE[a]
1975-1980
(GW.h)

	1975[b]	1976	1977	1978	1979	1980
New Brunswick						
Firm Power	1045	366	0	0	0	0
Unit Power	0	578	2618	1890	2467	2409
Economy Energy	555	869	489	295	1029	1056
Wheeled Power	0	71	365	376	319	393
TOTAL	1600	1884	3472	2561	3815	3858
Quebec						
Firm Power	11	11	10	94	146	306
Surplus Energy	902	497	548	722	4514	4796
Seasonal Diversity	0	0	0	586	3000	3000
Other	5	23	17	8	0	0
TOTAL	918	531	575	1410	7660	8102
Ontario						
Firm & Emergency Power[c]	1229	1646	3154	3985	3550	2503
Unit Power	49	35	35	22	16	3
Economy Energy	717	2423	5246	6379	8105	8219
TOTAL	1996	4104	8434	10386	11670	10725
Manitoba[d]						
Short-Term Firm Power	403	175	238	3482	3077	1352
Economy Energy	564	339	442	153	8	1424
Seasonal Diversity	0	0	0	0	0	263
Other	63	22	41	83	881	260
TOTAL	1030	536	721	3718	3966	3299
British Columbia						
Firm Power	321	10	11	11	11	12
Economy Energy[e]	1186	1290	3608	1666	1540	655
TOTAL	1507	1300	3618	1677	1551	666

SOURCE: Information from major provincial utilities.

[a] Totals may not add due to rounding. Export categories refer to historical utility classifications (see Glossary) and do not necessarily correspond to the categories adopted in this study.

[b] 1975 New Brunswick exports are taken from Canada, Department of Energy, Mines and Resources and United States, Department of Energy, Canada/United States Electricity Exchanges (Ottawa: Energy, Mines and Resources Canada, May 1979), p. 157.

[c] These two export types are aggregated by Ontario Hydro under a classification entitled "Capacity and Energy Assistance."

[d] Information pertains to the fiscal years 1975/76, 1976/77, 1977/78, 1978/79, 1979/80 and 1980/81.

[e] Includes a small amount for emergency power and Columbia River Treaty deliveries generally classified under "Interruptible Energy."

TABLE B.3

MAJOR (69 kV AND OVER) INTERCONNECTIONS BETWEEN THE UNITED STATES AND CANADA--EXISTING AND PLANNED

Province	State	In-Service Date	Voltage (kV)	Transfer Capability (MW)
New Brunswick	Maine	existing	345 138 69 69 69 69	700
Quebec	New York	existing	765 2 x 120	1350
	Vermont	existing	120	100
Ontario	New York	existing	230 230 2 x 230 69 69 2 x 69	900
	Michigan	existing	345 345 230 230	2000
	Minnesota	existing	120	35
Manitoba	North Dakota	existing	230	150
	Minnesota	existing	500	1000
		existing	230	175
Saskatchewan	North Dakota	existing	230	200
British Columbia	Washington	existing	2 x 500 230 230	2000
Quebec	New York	1984	±450	1000
Quebec	New England	1988	±450	690[a]
Ontario	New York	1984	2 x 345	2200
Manitoba[b]	Nebraska/Dakotas	1988+	500	1200

SOURCE: Canada, Department of Energy, Mines and Resources, Electric Power in Canada 1979 (Ottawa: Electrical Branch, 1980). Electric Power in Canada 1981 (Ottawa: Electrical Branch, 1982). Updated with information from utility sources.

[a] Expandable to 1800-2000 MW at a later date (1995).

[b] Under serious review.

TABLE B.4

INTERPROVINCIAL INTERCONNECTIONS--EXISTING AND PLANNED[a]

Interconnection	In-Service Date	Voltage (kV)		Capability (MW)
New Brunswick-Prince Edward Island	existing	2 x 138		100
New Brunswick-Nova Scotia	existing	2 x 138		
		345		600
New Brunswick-Quebec	existing	2 x ±230	HVDC	160
Quebec-Newfoundland	existing	3 x 735		4300
Quebec-New Brunswick	existing	2 x ±230	HVDC	300
Quebec-Ontario	existing	4 x 230		
		9 x 120		1300
Manitoba-Ontario	existing	2 x 230		
		115		260
Saskatchewan-Manitoba	existing	3 x 230		400
British Columbia-Alberta	existing	138		80
Quebec-New Brunswick[b]	1984	2 x 230	HVDC	500
British Columbia-Alberta	1985	500		800

SOURCE: Canada, Department of Energy, Mines and Resources, *Electric Power in Canada 1981*, (Ottawa: Electrical Branch, 1982). Updated with information from utilities.

[a] Excludes the proposed Western Grid to link Manitoba, Saskatchewan and Alberta, which has been postponed indefinitely.

[b] Under serious review.

APPENDIX C

U.S. ELECTRICITY DEMAND SCENARIOS

Appendix C

U.S. ELECTRICITY DEMAND SCENARIOS

The U.S. demand and capacity projections used in this study were derived from utility projections reported in the "1980 Summary of Projected Peak Demand, Generating Capability, and Fossil Fuel Requirements for the Regional Reliability Councils of NERC"[1] and associated bulk power supply programs plans reported[2] to the United States Department of Energy in April of 1980. The release of preliminary report "Electric Power Supply and Demand 1981 - 1990 for the Regional Reliability Councils of NERC" in June 1981 showed the new demand growth projection for the 1980s to be lower than that given in the 1980 report. Subsequently, three scenarios for growth in electricity consumption over the next two decades were defined. The high growth scenario is essentially the 1980 projection, whereas the mid growth or base case scenario corresponds to the 1981 projection. A low growth scenario is also defined.

At the time of this study, the complete data of the 1981 projections were not yet available. The demands under alternative scenarios were derived by adjusting the original 1980 projections by appropriate factors. The capacity corresponding to each of the demand scenarios was obtained by introducing a series of delays into the capacity array to match with the adjusted demand without decreasing the total annual reserve margin. The delays caused each type of capacity to be shifted from one time slot to the next. For example, a one year delay in 1983 caused the capacities in 1984 to be the same as the capacities in 1983. The capacities in 1985 were then those which were originally in the 1984 slot and so on. Capacities in a particular year could continue to be delayed as long as the total of the nine regions did not see a larger total demand than under the original (high growth) scenario.

It should be noted that these delays in the capacity array postpone retirements, as well as additions. The majority of retirements involve oil-fired capacity. However, during the period from 1980 to 2000, less than 10 percent of oil-fired capacity will be retired. Therefore, the error introduced by retirement delays should be negligible and should not affect the results of this study.

Subsequent to the completion of our demand analysis, NERC published the industry's firm 1981 projections of consumption, peak demand and installed capacity. Table C.1 compares these recent projections and our mid growth projections for the year 1990. Only minor differences are apparent. Therefore, the base case projections used in this study are consistent with the latest (1981) NERC forecasts.

Tables C.2 through C.8 present the 1980 regional demands, installed capacities and related forecasts to the year 2000, for the three scenarios used in this study.

TABLE C.1

COMPARISON OF STUDY AND 1981 NERC PROJECTIONS
FOR THE YEAR 1990

Region	Study Base Case (Mid Growth)			1981 NERC Reporting		
	Energy Demand (billion kW.h)	Peak Demand (GW)	Installed Capacity (GW)	Energy Demand (billion kW.h)	Peak Demand (GW)	Installed Capacity (GW)
ECAR	524	90.5	122.3	524	89.4	119.2
MAAC	214	39.4	58.2	214	41.8	56.5
MAIN	246	48.9	59.8	226	45.3	55.9
MARCA	158	29.4	35.5	150	27.8	33.6
NPCC-New York	126	23.5	34.8	127	24.1	35.6
NPCC-New England	100	18.8	26.4	111	20.4	26.9
WSCC-NWPP	234	43.6	52.1	255	46.2	53.4
WSCC-CANV	250	48.0	58.3	238	47.4	54.8
WSCC-RMPA & AZNM	120	21.2	29.2	127	22.1	33.1
Total	1972	363.3[a]	476.6	1972	364.5[a]	469.0

SOURCE: Tables C.4 and C.7 and National Electric Reliability Council, Electric Power Supply and Demand 1981-1990 for the Regional Reliability Councils of NERC (Princeton: NERC, July 1981), Tables 1, 2, 18, 18-S, 14, 14-S, 15, and 15-S.

[a] Non-coincident peak demand.

TABLE C.2

1980 U.S. REGIONAL DEMAND AND INSTALLED CAPACITY

U.S. Region	Installed Capacity (GW)							Demand	
	Nuclear	Coal	Oil Steam	Gas Steam	Hydro	Other	Total	Peak (GW)	Energy (Billion kW.h)
ECAR	5.6	74.9	5.4	0.1	0.6	7.2	93.7	65.9	386
MAAC	8.3	15.5	12.9	-	1.0	11.2	48.8	33.6	163
MAIN	7.6	28.5	4.6	0.4	0.5	4.1	45.7	36.4	178
MARCA	3.8	15.7	0.6	0.2	3.0	4.3	27.5	19.8	110
NPCC-New York	3.7	3.5	14.8	-	4.0	5.5	31.5	21.2	112
NPCC-New England	4.3	0.5	11.8	-	1.3	3.5	21.4	16.1	83
WSCC-NWPP	1.1	8.4	0.2	0.1	27.6	1.6	39.0	33.4	180
WSCC-CANV	1.0	3.9	21.5	1.0	8.0	5.0	40.4	37.5	190
WSCC-RMPA & AZNM	0.2	10.0	2.3	0.9	2.7	3.4	19.5	14.0	75

TABLE C.3

PROJECTED U.S. REGIONAL PEAK AND ENERGY DEMAND - HIGH GROWTH SCENARIO

Region	Peak Demand (GW)			Energy Demand (billion kW.h)		
	1985	1990	2000	1985	1990	2000
ECAR	82.0	99.5	141.6	480	576	822
MAAC	38.6	43.3	53.4	204	235	290
MAIN	43.8	53.8	79.5	221	270	401
MARCA	25.9	32.3	47.9	139	174	258
NPCC-New York	23.3	25.8	31.5	118	138	169
NPCC-New England	17.9	20.7	29.0	93	110	154
WSCC-NWPP	41.5	47.9	66.1	209	257	355
WSCC-CANV	43.7	52.8	71.6	226	274	373
WSCC-RMPA & AZNM	18.8	23.3	34.5	107	132	196

TABLE C.4

PROJECTED U.S. REGIONAL PEAK AND ENERGY DEMAND - MID GROWTH SCENARIO

Region	Peak Demand (GW)			Energy Demand (billion kW.h)		
	1985	1990	2000	1985	1990	2000
ECAR	77.8	90.5	125.2	456	524	727
MAAC	36.7	39.4	47.2	193	214	257
MAIN	41.6	48.9	70.3	210	246	354
MARCA	24.6	29.4	42.4	132	158	228
NPCC-New York	22.1	23.5	27.9	113	126	149
NPCC-New England	17.0	18.8	25.7	88	100	137
WSCC-NWPP	39.4	43.6	58.5	199	234	314
WSCC-CANV	41.5	48.0	63.3	214	250	330
WSCC-RMPA & AZNM	17.9	21.2	30.5	102	120	173

TABLE C.5

PROJECTED U.S. REGIONAL PEAK AND ENERGY DEMAND - LOW GROWTH SCENARIO

Region	Peak Demand (GW)			Energy Demand (billion kW.h)		
	1985	1990	2000	1985	1990	2000
ECAR	73.0	80.4	100.0	428	465	581
MAAC	34.4	35.0	37.7	181	190	205
MAIN	39.0	43.5	56.1	197	219	283
MARCA	23.1	26.1	33.8	123	140	182
NPCC-New York	20.7	20.9	22.2	105	112	119
NPCC-New England	15.9	16.7	20.5	82	89	109
WSCC-NWPP	36.9	38.7	46.7	186	208	251
WSCC-CANV	38.9	42.7	50.6	201	222	263
WSCC-RMPA & AZNM	16.7	18.8	24.4	96	107	139

TABLE C.6

PROJECTED U.S. REGIONAL INSTALLED CAPACITY BY TYPE - HIGH GROWTH SCENARIO
(in gigawatts)

Year	Generation Type	ECAR	MAAC	MAIN	MARCA	NPCC New York	NPCC New England	WSCC NWPP	WSCC CANV	WSCC RMPA AZNM
1985	Nuclear	11.4	12.6	15.5	3.8	4.5	7.8	5.9	6.3	2.2
	Coal	85.9	16.3	31.3	20.7	7.7	1.6	10.8	4.7	13.4
	Oil Steam	5.4	12.4	4.5	0.5	11.4	10.6	0.2	21.3	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.0	0.9
	Hydro	0.7	1.2	0.5	2.8	4.1	1.3	30.6	8.5	2.8
	Other	7.6	11.4	4.4	4.2	5.5	4.1	1.8	8.3	3.9
	Total	111.1	53.8	56.4	32.3	33.2	25.4	49.4	50.1	25.4
1990	Nuclear	14.1	15.8	17.6	4.0	5.6	8.8	8.7	7.1	3.4
	Coal	98.5	18.6	35.3	24.8	9.8	2.5	13.0	14.3	16.3
	Oil Steam	5.2	11.8	4.5	0.5	11.1	10.5	0.2	20.9	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.1	0.8
	Hydro	1.0	0.7	0.7	2.9	4.3	1.3	31.1	8.8	3.7
	Other	8.9	9.6	5.0	4.7	5.6	4.1	2.6	9.3	4.8
	Total	128.0	56.5	63.2	37.1	36.4	27.2	55.7	61.5	31.2
2000	Nuclear	21.8	16.2	26.3	5.7	5.6	12.7	13.1	13.8	5.8
	Coal	139.5	23.1	46.2	31.9	10.3	7.5	22.1	24.7	21.5
	Oil Steam	5.2	11.8	4.5	0.5	11.1	10.5	0.2	20.9	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.0	0.8
	Hydro	4.9	2.5	3.7	4.7	4.3	1.3	33.0	10.9	4.8
	Other	11.1	13.6	10.7	12.0	5.7	4.1	8.4	15.9	8.0
	Total	182.7	67.2	91.4	55.1	37.0	36.1	76.9	87.2	43.1

TABLE C.7

PROJECTED U.S. REGIONAL INSTALLED CAPACITY BY TYPE - MID GROWTH SCENARIO
(in gigawatts)

Year	Generation Type	ECAR	MAAC	MAIN	MARCA	NPCC New York	NPCC New England	WSCC NWPP	WSCC CANV	WSCC RMPA AZNM
1985	Nuclear	10.9	10.4	15.3	3.8	4.5	5.5	3.4	6.3	1.9
	Coal	82.9	16.3	31.3	19.8	7.7	1.6	10.4	4.4	12.3
	Oil Steam	5.4	12.6	4.5	0.5	11.4	10.6	0.2	21.0	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.0	0.9
	Hydro	0.6	1.0	0.5	2.9	4.1	1.3	30.4	8.4	2.8
	Other	7.6	11.4	4.3	4.2	5.5	4.1	1.9	7.2	3.8
	Total	107.6	51.6	56.0	31.5	33.2	23.1	46.3	48.4	24.0
1990	Nuclear	13.4	15.9	16.9	3.8	5.6	8.9	7.2	6.6	3.2
	Coal	94.0	18.7	33.1	24.0	8.3	1.6	11.7	11.1	15.4
	Oil Steam	5.3	11.8	4.5	0.5	11.1	10.5	0.2	20.9	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.0	0.8
	Hydro	0.7	1.2	0.5	2.8	4.2	1.3	30.7	9.0	3.1
	Other	8.7	10.7	4.6	4.2	5.5	4.0	2.2	9.7	4.4
	Total	122.3	58.2	59.8	35.5	34.8	26.4	52.1	58.3	29.2
2000	Nuclear	19.2	16.1	23.5	5.1	5.6	11.1	11.8	11.6	5.1
	Coal	126.0	22.1	42.7	29.5	9.9	5.5	19.3	21.3	19.9
	Oil Steam	5.2	11.8	4.5	0.5	11.1	10.5	0.2	20.9	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.0	0.8
	Hydro	3.6	2.1	2.7	4.1	4.3	1.3	32.5	10.2	4.4
	Other	10.4	12.7	8.9	9.6	5.6	4.0	6.5	13.8	7.0
	Total	164.7	64.7	82.4	49.0	36.5	32.5	70.4	78.8	39.5

TABLE C.8

PROJECTED U.S. REGIONAL INSTALLED CAPACITY BY TYPE - LOW GROWTH SCENARIO
(in gigawatts)

Year	Generation Type	ECAR	MAAC	MAIN	MARCA	NPCC New York	NPCC New England	WSCC NWPP	WSCC CANV	WSCC RMPA AZNM
1985	Nuclear	7.8	9.4	11.9	3.8	4.5	4.3	2.2	4.9	0.2
	Coal	78.6	15.7	30.4	18.0	5.0	1.6	8.4	4.2	11.2
	Oil Steam	5.5	12.7	4.8	0.5	13.3	10.6	0.2	21.4	2.3
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.0	0.9
	Hydro	0.6	1.0	0.5	2.8	4.1	1.3	28.2	7.7	2.8
	Other	7.3	11.1	4.2	4.2	5.5	4.1	1.9	6.9	3.6
	Total	100.0	49.8	52.0	29.6	32.4	22.0	41.0	46.1	21.0
1990	Nuclear	10.9	10.4	15.3	3.8	4.5	5.5	3.4	6.3	1.9
	Coal	82.9	16.3	31.3	19.8	7.7	1.6	10.4	9.4	12.3
	Oil Steam	5.4	12.6	4.5	0.5	11.4	10.6	0.2	21.0	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.0	0.9
	Hydro	0.6	1.0	0.5	2.9	4.1	1.3	30.4	8.4	2.8
	Other	7.6	11.4	4.3	4.2	5.5	4.1	1.9	7.2	3.8
	Total	107.6	51.6	56.0	31.5	33.2	23.1	46.3	53.4	24.0
2000	Nuclear	14.1	15.8	17.6	4.0	5.6	8.8	8.7	7.1	3.4
	Coal	98.5	18.6	35.3	24.8	9.8	2.5	13.0	14.3	16.3
	Oil Steam	5.2	11.8	4.5	0.5	11.1	10.5	0.2	20.9	2.2
	Gas Steam	0.2	-	0.1	0.2	-	-	0.1	1.1	0.8
	Hydro	1.0	0.7	0.7	2.9	4.3	1.3	31.1	8.8	3.7
	Other	8.9	9.6	5.0	4.7	5.6	4.1	2.6	9.3	4.8
	Total	128.0	56.5	63.2	37.1	36.4	27.2	55.7	61.5	31.2

Footnotes

[1] National Electric Reliability Council (Princeton: NERC, July 1980).

[2] Each of the nine U.S. reliability councils submitted Regional Reliability Reports to the Economic Regulatory Administration of the U.S. Department of Energy, which were then published in "Coordinated Bulk Power Supply Program 1979-1989," April 1, 1980.

APPENDIX D

ECONOMICS OF NEW U.S. COAL AND NUCLEAR FACILITIES

Appendix D

ECONOMICS OF NEW U.S. COAL AND NUCLEAR FACILITIES

In this appendix are reported a sample of projected costs for new coal and nuclear facilities in the United States. The purpose is to provide information from which the upper bound prices on Canadian dedicated capacity can be determined.

Since the lead times for installing new capacity will limit provincial supply capability for the next several years and since U.S. utilities already have enough capacity in various stages of constructon to supply their needs for the rest of the 1980s, the relevant time horizon is 1990 and beyond. Most of the U.S. capacity additions for the forecast period are either coal-fired or nuclear (see Table D.1); hence cost estimates are restricted to these two generating alternatives.

Data from three sources are presented. The first is the Electric Power Research Institute, a research organization funded by U.S. electric utilities. The second is Resources for Future, Inc., a well-known non-profit research organization located in Washington, DC. The third set of estimates is labeled REM data, being derived from some of the economic data used in the Regionalized Electricity Model (see Appendix E).

Table D.2 presents estimates from these three sources of the capital, operation and maintenance (O & M), and fuel costs for new coal generating facilities to be placed into commercial operation in 1990. Table D.3 presents similar data for new nuclear facilities. The range in capital and operating costs for each source is attributed to regional differences. Capital costs of new plants vary from one region to the next because of, among other things, differences in site characteristics, fuel handling requirements, indoor/outdoor construction requirements, labour productivities, and cooling requirements. The fuel costs vary with distance from supplying mines, sulfur and ash content of coals, and mine type.

Across sources there is substantial variation in the cost estimates. These reflect, in part, differing perspectives on the rates at which the costs of factors of production escalate in real terms, as well as differences in general costing methodology. Nonetheless, the estimates from all three sources are presented on equal footing to indicate a reasonable uncertainty band. The data for nuclear plants contain similar differences.

For the purpose of the dedicated capacity analysis reported in Chapter 4, REM cost estimates are adopted since they allow for a clear-cut differentiation among U.S. regions.

TABLE D.1

PROJECTED U.S. CAPACITY MIX

Region	Mid Growth Capacity Additions[a] 2000 over 1980 (GW)	Percent Nuclear[b]	Percent Coal[b]	Percent Other or Unspecified[b]
ECAR	71.6	19.1	71.4	9.5
MAAC	17.0	45.4	38.9	15.7
MAIN	37.1	42.8	38.3	18.9
MARCA	21.6	6.2	64.1	29.7
NPCC--New York	8.6	22.1	73.4	4.5
NPCC--New England	12.4	55.1	40.6	4.3
WSCC-NWPP	31.4	35.1	34.6	30.3
WSCC-CANV	39.1	26.9	44.4	28.7
WSCC-RMPA & AZNM	20.2	24.1	49.2	26.7
Total	259.0	28.3	52.3	19.4

[a] Values include additions necessary to replace scheduled retirements (and therefore do not agree with the information in Table 3.1).

[b] Regional Reliability Reports to the Economic Regulatory Administration of the Department of Energy published in "Coordinated Bulk Power Supply Program 1979-1989," April 1, 1980.

TABLE D.2

PROJECTED COSTS OF NEW U.S. COAL FACILITIES
(1980 $ U.S.)

1990 Commercial Operation of New 1050-1250 MW Base Load Unit	Installed Capital Cost ($/kW)	O & M Cost (mills/kW.h)	Fuel Cost (mills/kW.h)
EPRI	834-1076[a]	7.4[b]	12.8-23.5[b]
Resources for the Future	664-740[a]	3.2[b]	7.3-19.8[b]
REM Data	842-1222[c]	4.2	11.2-19.5

SOURCES: Electric Power Research Institute, "Technical Assessment Guide," EPRI PS-1201-SR (Palo Alto: EPRI, July 1979), pp. 8-15; S. H. Schurr et al., *Energy in America's Future: The Choices Before Us* (Baltimore: Resources for the Future, Johns Hopkins, 1979), pp. 197-288; and data from Tables D.4, D.5, D.6; and Appendix E.

[a] Values in source were given in other than 1980 dollars. They were escalated to 1980 dollars using the producer price index for construction of intermediate materials, supplies, and components from United States, Council of Economic Advisors, "Economic Report to the President" (Washington: United States Government Printing Office, 1981), p. 296.

[b] Values in source were given in other than 1980 dollars. They were escalated to 1980 dollars using the GNP price deflator from United States, Council of Economic Advisors, p. 235.

[c] The precision implied by the number of significant digits is overstated.

TABLE D.3

PROJECTED COSTS OF NEW U.S. NUCLEAR FACILITIES
(1980 $ U.S.)

1990 Commercial Operation of New 850-1000 MW Base Load Unit	Installed Capital Cost ($/kW)	O & M Cost (mills/kW.h)	Fuel Cost (mills/kW.h)
EPRI	943-1266[a]	1.9[b]	6.1-8.9[b,c]
Resources for the Future	790-879[a]	2.1[b]	6.8[b]
REM Data	999-1849[d]	2.8	6.6[c]

SOURCES: Electric Power Research Institute, "Technical Assessment Guide," EPRI PS-1201-SR (Palo Alto: EPRI, July 1979), pp. 8-15; S. H. Schurr et al., *Energy in America's Future: The Choices Before Us* (Baltimore: Resources for the Future, Johns Hopkins, 1979), pp. 197-288; and data from Tables D.4, D.5, and D.7.

[a] Values in source were given in other than 1980 dollars. They were escalated to 1980 dollars using the producer price index for construction of intermediate materials, supplies, and components from United States, Council of Economic Advisors, "Economic Report to the President" (Washington: United States Government Printing Office, 1981), p. 296.

[b] Values in source were given in other than 1980 dollars. They were escalated to 1980 dollars using the GNP price deflator from United States, Council of Economic Advisors, p. 235.

[c] Assumes no reprocessing.

[d] The precision implied by the number of significant digits is overstated.

TABLE D.4

UNIT CAPITAL COSTS FOR ECAR[a]
(1980 $/kW U.S.)

Year	Coal[b]	Nuclear
1980	819	1116
1990	905	1232
2000	999	1362

SOURCE: 1975 cost estimates from ICF Incorporated, The Economic and Financial Impacts of Environmental Regulations on the Electric Utility Industry, Final Report Prepared for the Edison Electric Institute (Washington: ICF Incorporated, February 1980), Tables B-11 and B-56.

[a] Based on real escalation of 1 percent per annum over the 1975 to 2000 period.

[b] Includes 62 $/kW (1975 $) for the installation of scrubbers to meet the Environment Protection Agency's orginal New Source Performance Standard of 1.2 lbs. $SO_2/10^6$ Btu.

TABLE D.5

REGIONAL CAPITAL COST MULTIPLIERS RELATIVE TO ECAR

Region	Coal Capital Cost Multiplier	Nuclear Capital Cost Multiplier
ECAR	1.00	1.00
MAAC	0.93	0.93
MAIN	0.97	0.81
MARCA	0.97	0.89
NPCC--New York	1.15	1.06
NPCC--New England	1.15	1.06
WSCC-NWPP	1.35	1.50
WSCC-CANV	1.35	1.50
WSCC-RMPA & AZNM	1.35	1.50

SOURCE: REM data.

TABLE D.6

PROJECTED OPERATING COSTS FOR NEW U.S. COAL FACILITIES[a]
(1980 mills/kW.h U.S.)

	1982		1990		2000	
U.S. Regions	Fuel	O & M	Fuel	O & M	Fuel	O & M
ECAR	13.6	4.2	14.7	4.2	17.9	4.2
MAAC	15.1		16.3		19.9	
MAIN	14.8		16.0		19.5	
MARCA	12.6		13.6		16.6	
NPCC-New York	18.0		19.5		23.8	
NPCC-New England	18.0		19.5		23.8	
WSCC-NWPP	10.3		11.2		13.7	
WSCC-CANV	10.3		11.2		13.7	
WSCC-RMPA & AZNM	10.3		11.2		13.7	

SOURCE: Derived from Tables E.1 and E.2.

[a] Fuel cost is based on a heat rate of 10 300 Btu/kW.h and real escalation of 1 percent and 2 percent between 1982 and 1990 and between 1990 and 2000, respectively. O & M cost includes no real escalation.

TABLE D.7

PROJECTED OPERATING COSTS FOR NEW U.S. NUCLEAR FACILITIES[a]
(1980 mills/kW.h U.S.)

1982		1990		2000	
Fuel[b]	O & M	Fuel[b]	O & M	Fuel[b]	O & M
6.6	2.8	6.6	2.8	7.3	2.8

SOURCE: Derived from REM Data and Table E.2.

[a] Fuel cost is based on real escalation of 0 percent and 1 percent between 1982 and 1990 and between 1990 and 2000, respectively. O & M cost includes no real escalation.

[b] Assumes no reprocessing.

APPENDIX E

REM DOCUMENTATION AND MODEL INPUTS

Appendix E

REM DOCUMENTATION AND MODEL INPUTS

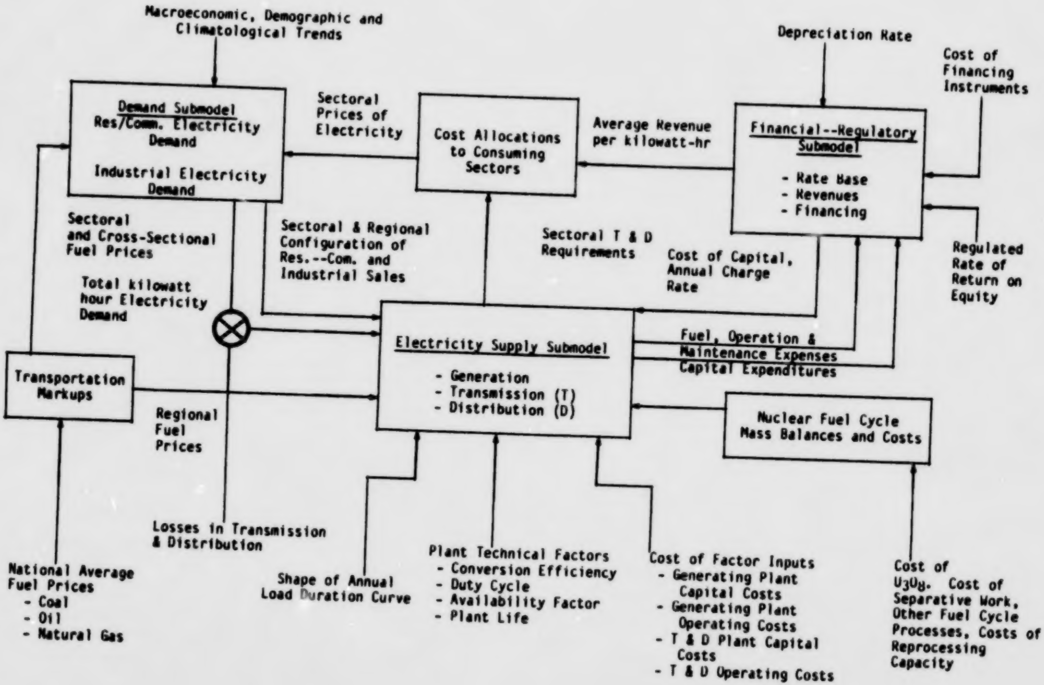
The Regionalized Electricity Model (REM) was developed in the United States by Martin Baughman and Paul Joskow. This engineering/economic simulation model has three critical submodels: electricity demand, financial-regulatory and electricity supply (see Figure E.1). It is well suited to the aggregate regional analysis of 1) electricity exports, 2) load forecasting, 3) the effects of alternative electricity rate levels and of shifts in the prices of electricity relative to other fuels, and 4) the rate of return on new generation and/or transmission investment by electric utilities.

Key input data associated with the energy demand and generation (energy supply) submodels for each region are:

- capacity by plant type;
- annual energy demand and peak loads;
- fuel costs;
- generating plant capital costs, heat rates, and operation and maintenance costs;
- costs of various transmission and distribution equipment items;
- monthly ratios of electrical energy demand and peak loads to annual demands and annual peak loads; and
- planned and forced outages of various types of generating plants.

The model then calculates for each of the regional aggregates over the projection period:

- the schedule for maintenance of generating plant by month of the year; and
- the least cost pattern of utilization of plant in operation each month to meet load and electrical energy requirements for the month.


Macroeconomic, Demographic and Climatological Trends
Demand Submodel
Res/Comm. Electricity Demand
Industrial Electricity Demand
Sectoral Prices of Electricity
Cost Allocations to Consuming Sectors
Average Revenue per kilowatt-hr
Depreciation Rate
Cost of Financing Instruments
Financial--Regulatory Submodel
- Rate Base
- Revenues
- Financing
Regulated Rate of Return on Equity
Sectoral and Cross-Sectional Fuel Prices
Sectoral & Regional Configuration of Res.--Com. and Industrial Sales
Sectoral T & D Requirements
Cost of Capital, Annual Charge Rate
Total kilowatt hour Electricity Demand
Electricity Supply Submodel
- Generation
- Transmission (T)
- Distribution (D)
Fuel, Operation & Maintenance Expenses
Capital Expenditures
Transportation Markups
Regional Fuel Prices
Nuclear Fuel Cycle Mass Balances and Costs
Losses in Transmission & Distribution
National Average Fuel Prices
- Coal
- Oil
- Natural Gas
Shape of Annual Load Duration Curve
Plant Technical Factors
- Conversion Efficiency
- Duty Cycle
- Availability Factor
- Plant Life
Cost of Factor Inputs
- Generating Plant Capital Costs
- Generating Plant Operating Costs
- T & D Plant Capital Costs
- T & D Operating Costs
Cost of U_3O_8. Cost of Separative Work, Other Fuel Cycle Processes, Costs of Reprocessing Capacity

SOURCE: Southwest Energy Associates, Inc., "United States Demand for Canadian Electricity Exports," Report Prepared for the Canadian Energy Research Institute, October 1981, p. 34.

FIGURE E.1: SCHEMATIC OF REM LINKAGES, EXOGENOUS DATA NEEDS, AND CENTRAL COMPUTATIONAL COMPONENTS

REM is used in this study to estimate the potential for Canadian electricity to displace existing oil-fired generation on a firm basis in the United States. This is relevant to the analysis of 'dedicated energy' sales presented in Chapter 4. In order to displace U.S. oil, Canadian electricity must be delivered at a cost between the marginal cost of oil (upper bound price) and the marginal cost of the next lower cost generation type, namely coal (lower bound price).

These marginal costs comprise fuel and operation and maintenance (O & M) components. Tables E.1 and E.2 summarize the raw data used to determine the upper and lower bound costs presented in the next appendix.

TABLE E.1

PROJECTED 1982 COAL AND OIL PRICES BY U.S. REGION ($US 1980/$10^6$ BTU)

Region	Coal[a]	Oil[b]
ECAR	1.32	4.76
MAAC	1.46	4.67
MAIN	1.43	4.59
MARCA	1.22	3.95
NPCC-New York	1.75	4.73
NPCC-New England	1.75	4.73
WSCC-NWPP	1.01	5.01
WSCC-CANV	1.01	5.01
WSCC-RMPA & AZNM	1.01	5.01

SOURCE: Derived from REM Data.

[a] Heat rates for new and existing coal plants are assumed to be 10 300 and 10 000 Btu/kW.h, respectively.

[b] Heat rates for existing oil plants are assumed to be 10 000 Btu/kW.h.

TABLE E.2

1980 ESTIMATED U.S. OPERATION AND MAINTENANCE COSTS BY PLANT TYPE[a]
(1980 mills/kW.h U.S.)

Plant Type	O & M Cost
Existing Oil	3.2
Existing Coal	3.7
New Coal	4.2
New Nuclear	2.8

[a] O & M costs were derived from estimates in 1975 dollars contained in M. L. Baughman and D. P. Kamat, Assessment of the Effect of Uncertainty on the Adequacy of the Electric Utility Industry's Expansion Plans, 1983 - 1990, Interim Report for the Electric Power Research Institute by the Center for Energy Studies at the University of Texas, Report EA-1446 (Palo Alto: EPRI, July 1980), Table C.3. Estimates were inflated to 1980 dollars using the Gross National Product implicit price deflator from United States, Department of Commerce, Bureau of Economic Analysis, Survey of Current Business, Washington, December 1980 and January 1982.

APPENDIX F

REM SIMULATIONS OF DEDICATED ENERGY DEMANDS

Appendix F

REM SIMULATIONS OF DEDICATED ENERGY DEMAND

For ease of comparison, the results of our simulated demands for dedicated energy are presented in terms of percent utilization of capacity or capacity factor. The objective was to determine the capacity factor that could be expected for each of the alternative capacity blocks hypothesized to be available, at the prices designated, to the nine U.S. consuming regions.

The resulting capacity factors for export blocks of 200 MW, 500 MW, 1000 MW and 2000 MW are depicted in Tables F.1 through F.12. Five alternative growth scenarios and three difference study years are considered.

The three left-hand columns of each table present information on the range of delivered price of the exports over which the demands in the right-hand columns can be expected to occur. The far left-hand column, labeled lower bound, represents the marginal cost of existing coal-fired generation in each of the regions. The other two columns represent the marginal cost of oil for two alternative fuel price scenarios. As long as the delivered price of the export is above this lower bound and below the appropriate upper bound, the capacity factors designated in the right-hand columns can be assumed to apply. If delivered price were below the lower bound, higher capacity factors would result because the exported energy could economically displace coal in the consuming region. If delivered price were higher than the upper bound, the resultant capacity factors would be much lower. Those instances where the resulting capacity factors exceed 50 percent have been boxed so as to highlight the more attractive exports markets for Canadian electricity. The capacity factors for the designated exports blocks are presented in the five right-hand columns of the tables. Each column represents a different growth scenario.

TABLE F.1

YEAR 1985 UTILIZATION OF 200 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	17.3	50.8	53.7	1.3	27.0	23.7	26.7	44.5
MAAC	18.7	49.9	52.8	55.4	74.6	74.6	71.2	85.8
MAIN	18.4	49.1	51.9	1.7	12.8	7.1	15.7	35.4
MARCA	16.3	42.7	45.1	1.0	14.4	14.3	18.7	43.2
NPCC-New York	21.7	50.5	53.4	49.1	80.3	57.0	66.7	94.0
NPCC-New England	21.7	50.5	53.4	79.7	99.6	97.8	90.6	99.9
WSCC-NWPP	14.1	53.3	56.4	-	38.1	-	-	67.8
WSCC-CANV	14.1	53.3	56.4	99.5	100.0	100.0	100.0	100.0
WSCC-RMPA & AZNM	14.1	53.3	56.4	2.0	77.2	50.7	34.9	91.8

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.2

YEAR 1990 UTILIZATION OF 200 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	18.0	50.8	59.0	-	27.7	26.2	33.4	56.9
MAAC	19.5	49.9	57.9	30.1	74.6	54.4	70.3	91.0
MAIN	19.2	49.1	57.0	1.2	15.1	23.9	31.4	50.6
MARCA	16.9	42.7	49.5	0.6	26.4	23.9	33.7	72.6
NPCC-New York	22.6	50.5	58.6	28.6	57.0	58.7	64.7	95.1
NPCC-New England	22.6	50.5	58.6	71.7	99.1	91.2	92.2	100.0
WSCC-NWPP	14.6	53.3	61.9	-	20.7	-	24.6	91.9
WSCC-CANV	14.6	53.3	61.9	89.9	100.0	96.4	95.2	100.0
WSCC-RMPA & AZNM	14.6	53.3	61.9	-	61.1	8.3	30.1	93.6

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.3

YEAR 2000 UTILIZATION OF 200 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case		(percent capacity factor)			
ECAR	21.1	50.8	71.2	-	33.8	21.4	23.8	76.6
MAAC	23.0	49.9	69.9	9.9	47.1	68.4	79.4	90.2
MAIN	22.6	49.1	68.8	-	38.5	32.3	36.6	78.3
MARCA	19.8	42.7	59.6	0.4	46.8	54.4	60.9	93.2
NPCC-New York	26.8	50.5	70.8	34.6	43.1	80.8	91.7	93.1
NPCC-New England	26.8	50.5	70.8	19.9	92.2	79.4	73.3	100.0
WSCC-NWPP	17.0	53.3	74.8	-	-	22.7	52.2	100.0
WSCC-CANV	17.0	53.3	74.8	8.1	94.7	89.7	88.6	100.0
WSCC-RMPA & AZNM	17.0	53.3	74.8	-	54.4	57.1	65.7	98.6

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.4

YEAR 1985 UTILIZATION OF 500 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	17.3	50.8	53.7	1.0	26.5	22.7	26.1	44.2
MAAC	18.7	49.9	52.8	53.2	73.6	73.8	70.5	85.0
MAIN	18.4	49.1	51.9	1.5	11.9	6.5	14.9	34.5
MARCA	16.3	42.7	45.1	0.8	12.8	12.7	17.2	40.1
NPCC-New York	21.7	50.5	53.4	48.0	77.8	55.1	62.4	92.1
NPCC-New England	21.7	50.5	53.4	77.3	99.1	97.2	88.4	99.8
WSCC-NWPP	14.1	53.3	56.4	-	35.4	-	-	67.6
WSCC-CANV	14.1	53.3	56.4	99.0	100.0	99.6	99.7	100.0
WSCC-RMPA & AZNM	14.1	53.3	56.4	1.4	73.9	40.8	28.2	89.4

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.5

YEAR 1990 UTILIZATION OF 500 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c] (percent capacity factor)				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case					
ECAR	18.0	50.8	59.0	-	27.0	25.6	33.1	56.6
MAAC	19.5	49.9	57.9	29.1	73.6	52.2	69.6	90.7
MAIN	19.2	49.1	57.0	1.1	14.3	23.2	30.5	50.0
MARCA	16.9	42.7	49.5	0.5	24.9	22.6	35.7	70.4
NPCC-New York	22.6	50.5	58.6	27.5	55.9	57.8	61.4	93.6
NPCC-New England	22.6	50.5	58.6	69.6	98.5	89.7	91.1	99.9
WSCC-NWPP	14.6	53.3	61.9	-	15.8	-	19.0	91.9
WSCC-CANV	14.6	53.3	61.9	87.3	100.0	96.2	95.0	100.0
WSCC-RMPA & AZNM	14.6	53.3	61.9	-	58.7	6.5	23.7	92.7

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.6

YEAR 2000 UTILIZATION OF 500 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	21.1	50.8	71.2	-	33.5	20.8	23.6	76.4
MAAC	23.0	49.9	69.9	9.2	46.1	67.8	78.8	89.9
MAIN	22.6	49.1	68.8	-	37.9	31.8	36.1	77.9
MARCA	19.8	42.7	59.6	0.4	45.6	53.0	59.9	92.7
NPCC-New York	26.8	50.5	70.8	32.8	40.0	80.0	71.8	92.4
NPCC-New England	26.8	50.5	70.8	18.7	91.1	77.9	91.0	99.9
WSCC-NWPP	17.0	53.3	74.8	-	-	14.9	52.1	100.0
WSCC-CANV	17.0	53.3	74.8	7.9	94.4	89.4	87.3	100.0
WSCC-RMPA & AZNM	17.0	53.3	74.8	-	47.3	55.5	62.7	98.4

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.7

YEAR 1985 UTILIZATION OF 1000 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	17.3	50.8	53.7	0.7	25.6	20.8	25.4	43.6
MAAC	18.7	49.9	52.8	50.2	72.0	72.2	69.2	83.4
MAIN	18.4	49.1	51.9	1.3	10.4	5.5	13.5	32.9
MARCA	16.3	42.7	45.1	0.5	10.1	10.2	14.8	35.4
NPCC-New York	21.7	50.5	53.4	46.1	72.1	52.7	59.3	88.5
NPCC-New England	21.7	50.5	53.4	73.6	98.1	96.0	84.8	99.4
WSCC-NWPP	14.1	53.3	56.4	-	31.0	-	-	67.4
WSCC-CANV	14.1	53.3	56.4	98.9	100.0	99.3	99.4	100.0
WSCC-RMPA & AZNM	14.1	53.3	56.4	0.8	68.1	29.1	20.4	86.4

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.8

YEAR 1990 UTILIZATION OF 1000 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	18.0	50.8	59.0	-	25.8	24.8	32.6	56.1
MAAC	19.5	49.9	57.9	27.1	72.0	49.5	68.3	90.1
MAIN	19.2	49.1	57.0	0.9	12.9	22.0	29.3	48.9
MARCA	16.9	42.7	49.5	0.3	22.5	20.4	32.8	67.0
NPCC-New York	22.6	50.5	58.6	25.6	52.5	54.7	57.9	90.7
NPCC-New England	22.6	50.5	58.6	66.0	97.4	86.0	88.9	99.8
WSCC-NWPP	14.6	53.3	61.9	-	8.4	-	12.7	91.8
WSCC-CANV	14.6	53.3	61.9	83.8	100.0	95.8	94.5	100.0
WSCC-RMPA & AZNM	14.6	53.3	61.9	-	52.0	4.7	17.0	91.1

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.9

YEAR 2000 UTILIZATION OF 1000 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	21.1	50.8	71.2	-	32.8	20.1	23.1	76.1
MAAC	23.0	49.9	69.9	8.2	43.5	66.6	77.8	89.3
MAIN	22.6	49.1	68.8	-	36.7	30.5	34.9	77.1
MARCA	19.8	42.7	59.6	0.3	43.5	50.2	57.9	91.3
NPCC-New York	26.8	50.5	70.8	30.7	35.6	76.6	88.3	90.9
NPCC-New England	26.8	50.5	70.8	15.4	88.7	76.1	69.4	99.6
WSCC-NWPP	17.0	53.3	74.8	-	-	11.8	48.2	100.0
WSCC-CANV	17.0	53.3	74.8	7.4	94.1	88.9	86.5	100.0
WSCC-RMPA & AZNM	17.0	53.3	74.8	-	36.5	49.3	60.1	98.1

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[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.10

YEAR 1985 UTILIZATION OF 2000 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	17.3	50.8	53.7	0.4	22.9	18.0	23.1	42.8
MAAC	18.7	49.9	52.8	45.0	68.3	68.9	65.8	80.8
MAIN	18.4	49.1	51.9	0.9	7.8	4.0	10.8	29.7
MARCA	16.3	42.7	45.1	0.3	5.9	6.1	10.1	29.0
NPCC-New York	21.7	50.5	53.4	39.5	63.0	48.5	54.5	82.0
NPCC-New England	21.7	50.5	53.4	66.6	95.1	91.6	78.6	97.8
WSCC-NWPP	14.1	53.3	56.4	-	17.9	-	-	59.6
WSCC-CANV	14.1	53.3	56.4	98.4	99.9	99.0	99.1	100.0
WSCC-RMPA & AZNM	14.1	53.3	56.4	0.4	54.3	16.4	11.5	78.8

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.11

YEAR 1990 UTILIZATION OF 2000 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case	(percent capacity factor)				
ECAR	18.0	50.8	59.0	-	23.1	23.1	31.7	55.1
MAAC	19.5	49.9	57.9	22.7	68.2	44.7	65.5	88.9
MAIN	19.2	49.1	57.0	0.6	10.2	19.6	26.9	46.6
MARCA	16.9	42.7	49.5	0.2	17.6	16.1	28.4	61.5
NPCC-New York	22.6	50.5	58.6	21.7	47.6	50.5	53.6	85.6
NPCC-New England	22.6	50.5	58.6	57.0	94.5	79.8	83.4	98.8
WSCC-NWPP	14.6	53.3	61.9	-	4.2	-	6.4	86.3
WSCC-CANV	14.6	53.3	61.9	78.2	99.5	95.0	93.8	100.0
WSCC-RMPA & AZNM	14.6	53.3	61.9	-	34.2	2.8	9.4	86.7

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.12

YEAR 2000 UTILIZATION OF 2000 MW CAPACITY TO DISPLACE OIL

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Actual Demand Growth(%)/Capacity Growth(%)[c]				
	Lower Bound[a]	Upper Bound[b]		2.0/3.4	2.0/2.0 (percent capacity factor)	3.1/3.1	3.4/3.4	3.4/2.0
		Low Fuel Price	Base Case					
ECAR	21.1	50.8	71.2	-	31.3	19.2	22.0	75.3
MAAC	23.0	49.9	69.9	6.5	38.7	63.2	75.8	87.7
MAIN	22.6	49.1	68.8	-	34.2	28.5	33.0	75.7
MARCA	19.8	42.7	59.6	0.1	38.0	46.2	54.8	87.8
NPCC-New York	26.8	50.5	70.8	27.0	30.7	68.0	84.2	87.0
NPCC-New England	26.8	50.5	70.8	10.2	82.9	71.4	65.4	98.5
WSCC-NWPP	17.0	53.3	74.8	-	-	6.8	40.5	100.0
WSCC-CANV	17.0	53.3	74.8	0	93.5	86.7	81.8	100.0
WSCC-RMPA & AZNM	17.0	53.3	74.8	6.6	22.4	35.3	55.8	97.1

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

[c] 'Perceived' demand growth to which capacity growth responds.

TABLE F.13

YEAR 2000 UTILIZATION OF CAPACITY TO DISPLACE OIL--MID GROWTH SCENARIO

Receiving Region	Range in Delivered Price of Energy 1980 Mills Per kW.h U.S.			Capacity in MW						
	Lower[a] Bound	Upper[b] Bound		200	500	1 000	2 000	5 000	10 000	20 000
		Low Fuel Price	Base Case	(percent capacity factor)						
ECAR	21.1	50.8	71.2	21.4	20.8	20.1	19.2	16.9	13.1	7.0
MAAC	23.0	49.9	69.9	68.4	67.8	66.6	63.2	50.8	33.8	17.3
MAIN	22.6	49.1	68.8	32.3	31.8	30.5	28.5	23.4	15.0	7.5
MARCA	19.8	42.7	59.6	54.4	53.0	50.2	46.2	34.0	19.2	9.6
NPCC-New York	26.8	50.5	70.8	80.8	80.0	76.6	68.0	52.4	34.0	17.1
NPCC-New England	26.8	50.5	70.8	79.4	77.9	76.1	71.4	58.5	35.4	17.7
WSCC-NWPP	17.0	53.3	74.8	22.7	14.9	11.8	6.8	2.7	1.4	0.7
WSCC-CANV	17.0	53.3	74.8	89.7	89.4	88.9	86.7	79.5	68.9	40.3
WSCC-RMPA & AZNM	17.0	53.3	74.8	57.1	55.5	49.3	35.3	15.7	7.8	3.9

[a] The lower bound costs correspond to marginal coal generation costs in each region.

[b] Fuel price scenarios of upper bound costs reflect different real escalation rates of world oil prices--2% under the base case and 0% under the low fuel price.

APPENDIX G

SEASONAL PEAK DEMAND FOR CANADIAN AND U.S. REGIONS

TABLE G.1

1982 SEASONAL PEAK DEMANDS FOR CANADIAN AND U.S. REGIONS

Regions	Season[a]			
	Winter	Spring	Summer	Fall
	(MW)			
Canadian Provinces				
Nova Scotia	1 235	1 073	967	1 147
New Brunswick	1 422	1 240	948	1 202
Quebec	21 199	17 947	12 823	18 506
Ontario	18 645	16 445	15 072	17 730
Manitoba	2 766	2 382	1 614	2 608
Saskatchewan	1 925	1 621	1 428	1 810
Alberta	4 422	3 662	3 501	4 273
British Columbia	6 560	5 340	4 710	4 260
U.S. Regions				
NPCC-New York	20 371	18 627	22 070	20 680
MAAC	30 767	27 989	35 610	31 907
MAIN	31 605	30 698	39 457	34 996
MARCA	18 642	15 071	20 595	17 996
WSCC-CANV	32 647	33 400	39 668	38 081

SOURCE: (1) U.S. data from Regional Reliability Reports to the Economic Regulatory Administration of the United States Department of Energy entitled "Coordinated Bulk Power Supply Program 1979-1989," and (2) Canadian data from correspondence with the major provincial utilities.

[a] Winter, Spring, Summer and Fall correspond to December through February, March through May, June through August and September through November, respectively.

TABLE G.2

POTENTIAL CAPACITY SAVINGS THROUGH
SEASONAL DIVERSITY INTERCHANGE, 1982
(GW)

Canadian/U.S. Region[a]	Unintegrated Peak Demands Plus 20% Reserve Margin	Integrated Peak Demands Plus Reserve Margin of:		Maximum Capacity Savings Under Integrated Reserve Margin of:	
		20%	25%	20%	25%
British Columbia					
and WSCC-CANV	55.5	53.3	55.5	2.2	none
Alberta					
and WSCC-CANV	52.9	51.8	54.0	1.1	none
and MARCA	30.0	28.9	30.1	1.1	none
Saskatchewan					
and MARCA	27.0	26.4	27.5	0.6	none
and WSCC-CANV	49.9	49.3	51.4	0.6	none
Manitoba					
and MARCA	28.0	26.7	27.8	1.3	0.2
and MAIN	50.7	49.3	51.3	1.4	none
Ontario					
and NPCC-New York	48.9	46.8	48.8	2.1	0.1
and MAAC	65.1	60.8	63.4	4.3	1.7
and MAIN	69.7	65.4	68.2	4.3	1.5
Quebec					
and NPCC-New York	51.9	49.9	52.0	2.0	none
and MAAC	68.2	62.4	65.0	5.8	3.2
and MAIN	72.8	64.2	66.9	8.6	5.9
New Brunswick					
and NPCC-New York	28.2	27.6	28.8	0.6	none
Nova Scotia					
and NPCC-New York	28.0	27.6	28.8	0.4	none

SOURCE: Derived from data in Table G.1

[a] Canadian regions refer to the major utilities in each province. All Canadian regions are winter peaking whereas all U.S. regions considered are summer peaking.

[b] If calculated integrated peak demands equal or exceed the unintegrated peak demands for each regional match, there is no incentive for seasonal diversity interchange and the maximum capacity savings are 'none'.

APPENDIX H

DELIVERED COST OF CANADIAN ELECTRICITY

Appendix H

DELIVERED COST OF CANADIAN ELECTRICITY

H.1 Hypothetical Generation Sites

Hypothetical generation sites have been selected for both dedicated and interruptible exports. For hydro provinces, dedicated facilities derive from site-specific projects in utility expansion plans. For thermal provinces, we use either site-specific projects or 'typical' facilities over the 1990 - 2000 period, in which case sites are assigned arbitrarily. Interruptible energy sales are assumed to originate from major facilities based on the type of marginal generation in each of the five provinces considered for this classification of export--New Brunswick, Quebec, Ontario, Manitoba and British Columbia.

H.1.1 Dedicated Exports

Newfoundland

Newfoundland's dedicated facility throughout the study period is its proposed Gull Island project (1700 MW) in the Lower Churchill River Basin of Labrador. Originally the first phase of Gull Island was tentatively slated for an in-service date of 1986. The entire project has since been deferred in Newfoundland and Labrador Hydro's expansion plan, and it is now felt that development would probably not be justified on the basis of domestic needs until the 1990s. The feasibility and timing of Gull Island depend on the province's ability to recall Churchill Falls power under its contract with Hydro-Quebec and, as well, on the construction of a major aluminum smelter on the mainland. Conceivably, however, power could be available for the study year 1990 if the Lower Churchill site were developed specifically with U.S. markets in mind, as either an export-dedicated or a prebuild project.

Nova Scotia

Nova Scotia's dedicated exports are predicated on a new coal-fired station composed of 300 MW units. A site in the vicinity of Halifax is chosen, although a new coal station could be built at a number of locations throughout the province, including the Cape Breton area.

New Brunswick

New Brunswick's hypothetical dedicated facility is another CANDU nuclear project at the site of Point Lepreau Unit 1. A second 630 MW unit, Point Lepreau 2, has been proposed for the late 1980s, with the possibility of a third unit for the late 1990s. The costs of additional nuclear units are based on information on Lepreau 2 from the New Brunswick Electric Power Commission.

Quebec

Hydro-Quebec is planning several large hydroelectric projects for the 1990s. Dedicated facilities for the 1990 and 2000 study years correspond to the Nottaway-Broadback-Rupert complex (6780 MW for both phases of NBR) south of James Bay and La Romaine (1420 MW) on the North Shore, respectively. Other projects such as the Grande Baleine complex (2900 MW) and Phase II of La Grande/James Bay (3170 MW in total) could also be considered.[1]

Ontario

In view of the growing interest in export-dedicated nuclear plants, exports from Ontario are costed using a typical CANDU nuclear station coming on stream in the 1990s. The station would be of the type under construction at the Darlington site on Lake Ontario; that is, it would consist of four 850 MW reactors. The plant is assumed to be located at the Bruce Complex on Lake Huron, given the preference for locating nuclear facilities away from population centres. However, the Darlington complex or a site even closer to the Ontario-U.S. border could be selected instead.

Manitoba

Manitoba's dedicated facility for 1990 is assumed to be its Limestone hydro station (approximately 1300 MW),[2] currently planned for a 1992 in-service date. As for the 2000 study year, one of Manitoba Hydro's options is a project at the Wuskatim site on the Burntwood River for the late 1990s; but at about 300-400 MW this development would not provide sufficient capacity for a 1000 MW export sale. Therefore, dedicated exports for the year 2000 are based on the proposed Conawapa site (roughly 1300 MW), downstream from Limestone on the Nelson River.

Saskatchewan

The most likely export plant for Saskatchewan throughout the 1990s would appear to be a two 280 MW lignite coal station of the kind under construction at Poplar River. Unfortunately, due to the delicacy of negotiations over the Western Grid, Saskatchewan Power Corporation has been unable to provide cost information on typical coal-fired units or on specific units in its generation expansion plan. As a result, estimates of delivered cost for the 1990 and 2000 study years are derived from data in an economic impact study relating to the proposed 2 x 280 MW coal station at Courval, southwest of Regina, which is tentatively scheduled for the late 1980s.[3]

Alberta

Over the entire forecast period, Alberta's dedicated exports are hypothesized to take place from a sub-bituminous coal-fired plant near Red Deer. Although a number of potential sites are available in the province, the Red Deer area was the proposed location for the export-dedicated coal station studied by Fording Coal, Alberta Power and TransAlta Utilities (see Chapter 4, Section 1.4). The dedicated facility is assumed to be a mine-mouth station composed of 375 MW units. The provincial Electric Utility Planning Council has provided 'representative' cost estimates from the 4 x 375 MW Keephills plant being built by TransAlta Utilities.[4]

British Columbia

For the 1990 study year, B.C. Hydro is assumed to dedicate capacity from its proposed Peace Site C (900 MW) and Murphy Creek (400 MW) developments. Delivered cost is based on a weighted average of the capital and operating costs of the two facilities, with Peace Site C contributing its full output and Murphy Creek contributing the 340 MW required to make up 1000 MW of delivered (i.e., after transmission losses) capacity. For the year 2000, dedicated exports originate from the province's northerly Iskut-Stikine project. A weighted average of cost estimates for the Iskut B (780 MW) and Stikine Z (915 MW) sites is used, with Stikine Z accounting for 490 MW of the total generating capacity required.

H.1.2 Interruptible Energy

New Brunswick

The marginal generation in the New Brunswick Electric Power Commission's existing system comes from oil-fired units, coal-fired units or purchases from Hydro-Quebec, depending on the time of year. Interruptible energy sales for 1990 assume that the utility proceeds with a policy of oil-fired conversions. Specifically, we assume that the 1000 MW Coleson Cove plant is converted to coal. In the year 2000, interruptible exports are assumed to be made from surplus generation at Point Lepreau.

Quebec

The marginal plant in Hydro-Quebec's system for the forecast period is assumed to be LaGrande 2 (5330 MW), the largest station in the LaGrande/James Bay complex.

Ontario

Ontario's interruptible exports for the 1990 study year are based on coal-fired generation from its 2920 MW Nanticoke station on Lake Erie. In 2000, on the other hand, the selected export facility is the Bruce A nuclear station (2960 MW) on Lake Huron.

Manitoba

Manitoba's marginal generation is hydraulic, and the specific units which respond to hourly swings in load are a function of system conditions. The delivered cost of interruptible energy for the two study years is calculated using the 1270 MW Kettle Rapids station on the Nelson River.

British Columbia

At the present time, B.C. Hydro's marginal generating units are also all hydraulic.[5] The representative marginal plant for British Columbia is Gordon M. Shrum (2420 MW) on the Peace River.

H.2 Cost Assumptions and Methodology

H.2.1 Dedicated Exports

For the hypothetical export-dedicated facilities listed above, utilities were asked to provide estimates of: 1) capital cost in 1980 dollars per kilowatt ($/kW); 2) fixed operation and maintenance (O & M) cost in millions of 1980 dollars per year ($MM/yr); 3) variable O & M cost in 1980 mills per kilowatt-hour (mills/kW.h); and 4) fuel cost in 1980 mills/kW.h.

Capital Costs

With respect to capital costs, utilities responded in some cases with in-service costs including escalation and interest during construction (IDC). Because our object was to derive 1980 capital costs including IDC at a specified rate, these reported costs were then de-escalated to 1980 using utility or assumed annual escalation rates. In cases where costs were already in 1980 dollars and included IDC, no alterations were made to the data; that is, no attempt was made to extract the utility IDC and recalculate interest on the basis of a common interest rate across utilities. In the third event, where costs were expressed in 1980 dollars excluding interest during construction, IDC was arbitrarily added at a real annual rate of 7 percent, which is within the range of 'social discount rates' estimated from Canadian historical investment data.[6] The procedure for calculating IDC was to allocate the constant dollar capital cost over an assumed construction profile and compute interest on the accumulated total debt in each year. The assumed construction profiles were as follows:

Construction Year	Hydro or Nuclear Station	Coal-fired Station
1	5%	5%
2	10%	15%
3	20%	35%
4	35%	30%
5	20%	15%
6	10%	

Utility cost estimates are used, with no adjustments for potential project overruns. All capital costs (i.e., for both generation and transmission) are assumed to escalate in real terms at the rate of 1 percent per annum between 1980 and 2000, to reflect historically rapid inflation in the construction industry. In order to derive a 1980 cost in 1980 dollars, the capital cost of a facility is escalated at 1 percent per year until the particular study year--1990 or 2000--in which it is assumed to come in service.

Total capital cost has been pro-rated for a hypothetical export volume of 1000 MW. We have assumed that utilities install enough generating units at least to cover the 1000 MW sale (e.g., two 630 MW CANDU units for New Brunswick, a 4 x 850 MW nuclear station in Ontario) and that surplus capacity is used for domestic purposes. In the case of coal-fired facilities, this has resulted in a lower average or unit ($/kW) capital cost. It is the nature of coal stations that the cost of successive units is less than the cost of the first unit. Since all the data from coal-based utilities pertained to stations of under 1000 MW, further units have been arbitrarily added, lowering the $/kW cost of the station. In practice, this type of expansion may not be technically feasible. The size of a thermal station at any particular site depends upon local water supply and availability of fuel. However, we assume that a station of over 1000 MW can be supported in each province. Indeed, one of the drawing points of export-dedicated or prebuild generating stations is that smaller utilities may be able to take advantage of economies of scale by building larger facilities than domestic demands allow.[7]

To calculate Canadian generation cost, capital cost is amortized or 'annuitized' using a capital recovery factor:

Annual capital cost (ACC) = Capital cost ($MM) x CRF (1/yrs)
($MM/yr)

$$\text{where CRF} = \frac{r}{1 - (1 + r)^{-T}}$$

r = real discount rate (%)
T = amortization period (yrs)

The unit energy cost for capital amortization (UECCA) is then calculated by dividing through by the amount of energy:

$$\underset{\text{(mills/kW.h)}}{\text{UECCA}} = \frac{\text{ACC (\$MM/yr)}}{\text{Capacity factor (\%)} \times \text{Capacity (GW)} \times 8760 \text{ (hrs/yr)}} \times 1000 \text{ (mills/\$)}$$

The base case real discount rate is 7 percent, with 4 percent and 10 percent for sensitivity purposes. The 4 percent value is within the range of long-term utility bond rates adjusted for inflation. The 7 and 10 percent values correspond to estimates of the real rate of return on investment in alternative sectors of the economy (social discount rates).[8] As for the amortization periods, these are included in the summary of costing assumptions in Table H.1. Generation facilities are amortized over their estimated useful lives. Transmission equipment is amortized over 25 years, the maximum term of a National Energy Board licence. The useful lives of lines and terminals could be much longer; in fact, utilities use up to 40 years for HVDC equipment in determining depreciation expense. However, the term of an export licence is used in order to be consistent with the rule for oil and gas pipelines.

Capacity factors are listed in Table H.2. (Interruptible energy is based on an 'illustrative' energy block of 5000 GW.h.) Dedicated capacity exports assume a 'typical' base load capacity factor of 70 percent. Dedicated energy exports are based on the specific capacity factors at which power is demanded to displace 1000 MW blocks of oil-fired capacity in the U.S. regions. These demand-side capacity factors are constrained by supply-side 'availability factors'[9] of 95, 85 and 75 percent for hydro, nuclear and coal-fired units, respectively. Although most thermal generating units demonstrate availability factors in the 75 to 80 percent range, CANDU nuclear reactors are assigned an 85 percent factor in view of recent high performance levels in Ontario.

Operating Costs

Like capital cost, the fixed operation and maintenance cost of the dedicated facility is pro-rated for 1000 MW of capacity and converted to a unit energy cost:

$$\begin{array}{l}\text{Unit fixed}\\ \text{O \& M Cost}\\ \text{(mills/kW.h)}\end{array} = \frac{\text{Annual fixed O \& M cost (\$MM/yr)}}{\text{Capacity factor (\%)} \times \text{Capacity (GW)} \times \text{8760 (hrs/yr)}} \times \text{1000 (mills/\$)}$$

Unit operating cost consists of this value plus the variable O & M and fuel costs, both of which are expressed in mills per kW.h. The total unit energy cost of generation is then given by the sum of unit operating cost and unit energy cost for capital amortization.

The real escalation rates for O & M and fuel are shown in Table H.1. (These also apply to interruptible energy exports.) The rates for uranium and coal are considered appropriate in light of foreseen demand and supply conditions and in relation to our base case scenario for world oil prices--2 percent annual real escalation between 1980 and

TABLE H.1

COSTING ASSUMPTIONS

Interest During Construction (IDC)	7% (real)		
Real Discount Rate	4% 7% (Base Case) 10%		
Amortization Periods	70 years hydro station 40 years nuclear station 35 years coal-fired station 25 years transmission lines and terminals		
Annual Real Escalation Rates		1980-1990	1990-2000
	Capital Costs	1%	1%
	O & M	0%	0%
	Uranium	0%	1%
	Coal	1%	2%
	Oil (Base Case)	2%	2%
	Oil (Low Fuel Price)	0%	0%

TABLE H.2

CAPACITY FACTORS USED IN CALCULATING DELIVERED COST OF DEDICATED EXPORTS[a]

	1990		2000	
Dedicated Capacity			70%	
Dedicated Energy				
	Low	Mid	Low	Mid
NPCC-New England	97%	86%	89%	76%
NPCC-New York	53%	55%	36%	77%
MARCA	23%	20%	44%	50%
WSCC-CANV	100%	96%	94%	89%

[a] Capacity factors have been assumed except in the case of Dedicated Energy which is based on the capacity factors at which 1000 MW is demanded under the low (2.0% annual) and mid (3.1% annual) growth scenarios for U.S. demand and capacity (from Tables F.8 and F.9). These capacity factors are subject to the following 'availability factors' for Canadian generating units:

Hydro	95%
Nuclear	85%
Coal	75%

2000. The assumption of no real growth in uranium costs throughout the 1980s reflects the present glut in the world uranium market.

H.2.2 Interruptible Energy

For interruptible energy sales, utilities were asked to provide data on the production costs of marginal generating units in their systems. In most cases, they identified a type of generation--hydro, coal or nuclear--and an associated incremental operating (O & M and fuel) cost in mills per kW.h. This incremental operating cost is based on the capacity factors at which the marginal units are operated for the utility's integrated system.

Footnotes

[1] All installed capacities are taken from Hydro-Quebec, "A Strategy for the 80's" (Montreal: Hydro-Quebec, December 1980), pp. 46-47.

[2] Note this capacity figure differs from the 1080 MW reported for Limestone in our economic impact analysis (see Chapter 5, Table 5). One of the difficulties in costing undeveloped hydro sites is that their estimated capacities are often subject to change. The smaller figure in Chapter 5 is taken from an economic impact study on the western grid (see below under Note 3). The larger figure is an updated capacity estimate obtained directly from Manitoba Hydro.

[3] Marvin Shaffer and Associates Ltd., Western Electric Power Grid Benefit Study: Socio-Economic Impact Analysis (Vancouver: Marvin Shaffer and Associates Limited, October 1980), pp. 15-16. The capital cost of the Courval plant includes expenditures on the generating station, the coal mine at Poplar River, and the railway and rolling stock for transporting the coal. Since capital expenditures on the station have not been broken down by generating unit, the capital cost of the second 280 MW unit in service is arbitrarily assumed to be 70 percent of the cost of the first unit. This former cost is then applied to the successive units required to make up a 1000 MW sale (see under H.2). Operating costs for the Courval project are based on a capacity factor of 45 percent. In view of these limiting assumptions, our calculations of delivered cost for Saskatchewan can at best be regarded as rough estimates.

[4] Two units are under construction at Keephills and TransAlta Utilities has submitted an application for two additional units.

[5] This will probably hold for the forecast period as well, since B.C. Hydro has postponed indefinitely its Hat Creek thermal project.

[6] See below under Note 8.

[7] This form of economies of scale refers to station size as opposed to unit size. But economies through increased unit size are also possible. For example, New Brunswick and Quebec could build the 850 MW CANDU reactors which Ontario Hydro finds most efficient.

[8] The long-term real interest rate facing utilities in financial markets is in the range of 3 to 6 percent. See British Columbia Hydro and Power Authority, "Appropriate Discount Rates for Project Evaluation," Draft Paper for the Committee on Project Evaluation Procedures (Vancouver: System Engineering Division, January 1980) and R. Drapkin, "Energy Analysis of Major Household Appliances," Report for The Canadian Electrical Association (Toronto: Ontario Hydro, March 1981). The 7 percent discount rate corresponds to a

fairly recent estimate of the 'social discount rate' made by David Burgess in *The Social Discount Rate for Canada: Theory and Measurement* (Ottawa: Economic and Policy Analysis Sector, Energy, Mines and Resources Canada, 1980). An earlier study by Glenn Jenkins using Canadian investment data for the period 1965 - 74 resulted in the 10 percent estimate that is used by the Treasury Board in its cost-benefit analysis. See *Capital in Canada: Its Social and Private Performance 1965 - 74* (Ottawa: Economic Council of Canada, October 1977).

[9] The availability factor of a generating unit relates to its ability to perform without planned or forced outages.

APPENDIX I

POTENTIAL NET REVENUES FROM CANADIAN ELECTRICITY EXPORTS

Appendix I

POTENTIAL NET REVENUES FROM CANADIAN ELECTRICITY EXPORTS

The potential net revenue or surplus from a given export sale is equal to U.S. replacement cost minus the delivered cost of Canadian electricity. In this appendix, potential net revenues to prospective exporting utilities are computed for three of the four classes of export sale--dedicated capacity, dedicated energy and interruptible energy. Dedicated capacity and dedicated energy are based on 1000 MW of Canadian capacity delivered to the U.S. region, while interruptible energy is based on a 5000 GW.h energy sale. Each Canadian province is matched with a single U.S. market across the three export types. Newfoundland, Nova Scotia and New Brunswick are matched with NPCC-New England, Quebec and Ontario are matched NPCC-New York, and Alberta and British Columbia are matched with the California-Nevada subregion (WSCC-CANV). All of these U.S. markets are expected to rely considerably on existing oil-fired generation throughout the forecast period. The potential for oil displacement is not as great, however, in MARCA (the Dakotas, Minnesota, etc.); nevertheless, this market is assigned to Manitoba and Saskatchewan because of the transmission distances involved to more promising markets.

While a single U.S. market is adopted for ease of analysis, several provinces could export to a number of different U.S. markets, either across export classes or for the same class. For example, Ontario could sell dedicated capacity to the ECAR (Michigan, Ohio, Indiana, etc.) and MAIN (Illinois, Wisconsin, etc.) regions, where considerable coal-fired additions are planned for the 1990 - 2000 period, and dedicated and interruptible energy to the oil-dependent NPCC and MAAC (Pennsylvania, Delaware, etc.) regions. A study of the U.S. capacity growth scenarios in Appendix C and the capacity factors to displace oil in Appendix F will reveal the more promising potential markets for each type of export.

I.1 Delivered Demand Price for Canadian Electricity

Both dedicated capacity and dedicated energy exports are priced at the full U.S. replacement cost, whereas interruptible energy sales are priced according to the traditional 'split savings formula', that is, mid-way between replacement cost and the delivered cost of the export. The pricing rule for dedicated sales produces the most optimistic scenario for Canadian utilities, in the sense that they appropriate the full surplus from export.[1] For this reason, the net revenues shown below are termed 'potential' and constitute upper bounds on the revenues which utilities could expect to receive in actual transactions with U.S. utilities. Actual utility revenues will differ from these potential values to the extent that reliability of supply considerations and bargaining between the respective utilities result in final export prices below our upper bound demand prices.

Tables I.1 and I.2 present the U.S. replacement costs used in calculating delivered prices for Canadian electricity. These costs are based on the REM data contained in Appendices D and F. All U.S. dollar values have been converted to Canadian dollars using an assumed long-term exchange rate of $1 Canadian = $0.85 U.S.

I.2 Calculation of Potential Net Revenues

The estimated net revenues from dedicated capacity, dedicated energy and interruptible energy exports are depicted in Tables I.3 through I.19. Results are shown for alternative discount rates, world oil price scenarios, and U.S. growth scenarios for capacity and demand. All potential net revenues are expressed both in 1980 mills per kW.h ('unit net revenues') and millions of 1980 dollars ('total net revenues'). Total net revenue is obtained by multiplying unit net revenue by the amount of exported energy, which is calculated as follows:

$$\text{Energy (GW.h)}^{2} = [1000 \text{ MW} \times \text{Capacity factor (\%)} \times 8760 \text{ (hrs/yr)}] \times .001 \text{ (MW/GW)}$$

Table I.20 summarizes the potential net revenues to Canadian utilities by export type, for different study years and assumptions. For each of the preceding tables a total net revenue is computed by summing the provincial utility net revenues, excluding any negative values which would imply uneconomic sales. From the U.S. demand side, this summation is generally valid for both dedicated capacity and dedicated energy exports under the low and mid growth scenario for capacity and demand.[3] Table 7 in Appendix C, which contains the regional increments to installed capacity, indicates that each of the U.S. markets considered here could conceivably absorb 1000 MW blocks of dedicated capacity from all of its prospective suppliers between 1990 and 2000. Likewise, in each market the capacity factors for dedicated energy remain reasonably high for capacity blocks of 2000 MW and above (see for example Table F.13, 'Year 2000 Utilization of Capacity to Displace Oil--Mid Growth Scenario'). Presumably, since the potential market for dedicated energy is substantial, the market for interruptible energy to displace high cost oil should be substantial as well. However, the amounts of interruptible energy which can be absorbed by U.S. markets will also depend on technical factors such as the capability and loading of transmission lines between the participating regions.

Because of these technical constraints and because interruptible sales are considered only for five of the nine provinces under study, it is difficult to compare total utility net revenues across the three classes of export sale. Moreover, dedicated exports have been priced according to the most optimistic scenario for Canadian utilities, that is at full U.S. replacement cost, whereas interruptible exports have been priced according to the split savings rule. Nevertheless, Table I.20 does give an indication of the relative magnitudes involved, and of the potentially lucrative market for displacing oil-fired generation in the United States.

TABLE I.1

PROJECTED TOTAL COST OF NEW U.S. COAL-FIRED AND NUCLEAR GENERATING FACILITIES[a]
STUDY YEAR 2000

(1980 mills/kW.h Canadian unless otherwise indicated)

	Facility Type	Capital (1980 $/kW Can.)	Capital[b]	O & M	Fuel	Total
NPCC	Coal	1352	17.0	4.9	28.0	49.9
MARCA	Coal	1140	14.4	4.9	19.5	38.8
WSCC	Nuclear	2404	29.4	3.3	8.6	41.3

SOURCE: Tables D.4, D.5, D.6 and D.7.

[a] Used in determining demand prices for dedicated capacity exports. All U.S. dollar costs have been converted to Canadian dollars using an exchange rate of $1 Canadian = $0.85 U.S.

[b] Unit energy costs for capital amortization are derived using a 7 percent real discount rate, 70 percent capacity factor, and assumed lives of 35 and 40 years for coal and nuclear, respectively.

TABLE I.2

PROJECTED MARGINAL COST OF EXISTING U.S. OIL-FIRED GENERATION[a]
(1980 mills/kW.h Canadian)

Fuel Price Scenario	Base Case[b]		Low[c]	
Study Year	1990	2000	1990	2000
NPCC	68.9	83.3	59.4	59.4
MARCA	58.2	70.1	50.2	50.2
WSCC	72.8	88.0	62.7	62.7

SOURCE: Tables F.8 and F.9.

[a] Used in determining demand prices for dedicated energy and interruptible energy exports. All U.S. dollar costs have been converted to Canadian dollars using an exchange rate of $1 Canadian = $0.85 U.S.

[b] 2% annual real escalation in world oil prices.

[c] 0% annual real escalation in world oil prices.

TABLE I.3

POTENTIAL NET REVENUES FROM DEDICATED CAPACITY EXPORTS[a]
2000 STUDY YEAR
BASE CASE[b]

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[c] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor (%)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	13	11	24	4	27	50	23	70	6130	139
Nova Scotia	Coal	39	6	45	6	51	50	-1	70	6130	-9
New Brunswick	Nuclear	35	3	38	6	44	50	6	70	6130	39
NPCC-New York:											
Quebec	Hydro	21	9	31	6	36	50	14	70	6130	84
Ontario	Nuclear	27	4	30	6	36	50	14	70	6130	86
MARCA:											
Manitoba	Hydro	13	9	22	5	27	39	12	70	6130	71
Saskatchewan	Coal	26	4	30	9	39	39	0	70	6130	0
WSCC-CANV:											
Alberta	Coal	26	6	31	17	48	41	-7	70	6130	-40
British Columbia	Hydro	19	11	30	16	46	41	-4	70	6130	-26

[a] For a U.S. purchase of 1000 MW of dedicated capacity. The sum of individual entries may not equal the total due to rounding.

[b] Capital costs are annuitized using a 7% real discount rate.

[c] The U.S. demand prices correspond to the total cost of a typical coal-fired facility in NPCC and MARCA and a typical nuclear facility in WSCC-CANV for the year 2000 (from Table I.1).

TABLE 1.4

POTENTIAL NET REVENUES FROM DEDICATED CAPACITY EXPORTS[a]
4 PERCENT DISCOUNT RATE
2000 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor (%)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	8	8	16	3	19	50	31	70	6130	189
Nova Scotia	Coal	36	5	40	5	45	50	5	70	6130	27
New Brunswick	Nuclear	26	3	29	4	33	50	17	70	6130	103
NPCC-New York:											
Quebec	Hydro	13	7	21	4	25	50	25	70	6130	154
Ontario	Nuclear	20	3	23	4	27	50	23	70	6130	140
MARCA:											
Manitoba	Hydro	8	7	15	4	19	39	20	70	6130	120
Saskatchewan	Coal	21	3	24	7	31	39	7	70	6130	45
WSCC-CANV:											
Alberta	Coal	22	5	26	13	39	41	2	70	6130	12
British Columbia	Hydro	13	8	21	12	33	41	8	70	6130	51

[a] For a U.S. purchase of 1000 MW of dedicated capacity. The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the total cost of a typical coal-fired facility in NPCC and MARCA and a typical nuclear facility in WSCC-CANV for the year 2000 (from Table 1.1).

TABLE I.5

POTENTIAL NET REVENUES FROM DEDICATED CAPACITY EXPORTS[a]
10 PERCENT DISCOUNT RATE
2000 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor (%)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	19	13	32	4	36	50	14	70	6130	84
Nova Scotia	Coal	43	7	50	8	58	50	-8	70	6130	-49
New Brunswick	Nuclear	44	4	48	7	55	50	-5	70	6130	-33
NPCC-New York:											
Quebec	Hydro	30	12	42	7	48	50	2	70	6130	9
Ontario	Nuclear	34	4	39	7	46	50	4	70	6130	26
MARCA:											
Manitoba	Hydro	18	12	30	6	36	39	3	70	6130	18
Saskatchewan	Coal	31	5	36	11	47	39	-8	70	6130	-50
WSCC-CANV:											
Alberta	Coal	30	7	37	20	57	41	-16	70	6130	-98
British Columbia	Hydro	26	13	40	19	59	41	-18	70	6130	-109

[a] For a U.S. purchase of 1000 MW of dedicated capacity. The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the total cost of a typical coal-fired facility in NPCC and MARCA and a typical nuclear facility in WSCC-CANV for the year 2000 (from Table I.1).

TABLE 1.6

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
1990 STUDY YEAR
BASE CASE[b]

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[c] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	10	8	18	3	20	69	49	86	7530	367
Nova Scotia	Coal	33	5	38	5	43	69	26	75	6570	171
New Brunswick	Nuclear	27	3	29	4	33	69	36	85	7450	264
NPCC-New York:											
Quebec	Hydro	23	9	32	6	38	69	31	55	4790	146
Ontario	Nuclear	31	4	35	7	41	69	28	55	4790	133
MARCA:											
Manitoba	Hydro	37	28	65	16	81	58	-23	20	1790	-41
Saskatchewan	Coal	56	12	68	27	94	58	-36	20	1790	-64
WSCC-CANV:											
Alberta	Coal	22	5	27	14	40	73	33	75	6570	213
British Columbia	Hydro	14	6	20	10	30	73	43	95	8320	354

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.8). The sum of individual entries may not equal the total due to rounding.

[b] Capital costs are annuitized using a 7% real discount rate.

[c] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the base case U.S. fuel price scenario (2% real escalation in world oil prices). See Table 1.2.

TABLE 1.7

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
4 PERCENT DISCOUNT RATE
1990 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	6	6	12	2	14	69	55	86	7530	413
Nova Scotia	Coal	30	4	34	4	38	69	31	75	6570	204
New Brunswick	Nuclear	20	2	22	3	26	69	43	85	7450	322
NPCC-New York:											
Quebec	Hydro	14	7	21	5	26	69	43	55	4790	204
Ontario	Nuclear	23	3	26	5	31	69	38	55	4790	182
MARCA:											
Manitoba	Hydro	23	22	45	12	57	58	1	20	1790	2
Saskatchewan	Coal	42	9	51	21	71	58	-13	20	1790	-24
WSCC-CANV:											
Alberta	Coal	18	4	22	11	33	73	40	75	6570	260
British Columbia	Hydro	10	4	14	8	22	73	51	95	8320	423

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.8). The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the base case U.S. fuel price scenario (2% real escalation in world oil prices). See Table 1.2.

TABLE 1.8

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
10 PERCENT DISCOUNT RATE
1990 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	14	10	24	3	27	69	42	86	7530	318
Nova Scotia	Coal	36	6	42	6	48	69	21	75	6570	135
New Brunswick	Nuclear	34	3	37	5	42	69	27	85	7450	199
NPCC-New York:											
Quebec	Hydro	32	11	43	8	51	69	18	55	4790	84
Ontario	Nuclear	39	5	44	8	52	69	16	55	4790	79
MARCA:											
Manitoba	Hydro	51	36	87	20	107	58	-49	20	1790	-87
Saskatchewan	Coal	72	15	86	33	120	58	-62	20	1790	-110
WSCC-CANV:											
Alberta	Coal	25	6	31	17	48	73	25	75	6570	161
British Columbia	Hydro	19	7	26	13	39	73	34	95	8320	280

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.8). The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the base case U.S. fuel price scenario (2% real escalation in world oil prices). See Table 1.2.

TABLE 1.9

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
LOW OIL PRICE[b]
1990 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	10	8	18	3	20	59	39	86	7530	296
Nova Scotia	Coal	33	5	38	5	43	59	17	75	6570	109
New Brunswick	Nuclear	27	3	29	4	33	59	26	85	7450	193
NPCC-New York:											
Quebec	Hydro	23	9	32	6	38	59	21	55	4790	101
Ontario	Nuclear	31	4	35	7	41	59	18	55	4790	88
MARCA:											
Manitoba	Hydro	37	28	65	16	81	50	-31	20	1790	-55
Saskatchewan	Coal	56	12	68	27	94	50	-44	20	1790	-79
WSCC-CANV:											
Alberta	Coal	22	5	27	14	40	63	22	75	6570	147
British Columbia	Hydro	14	6	20	10	30	63	33	95	8330	270

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Canadian capital costs are annuitized using a 7% real discount rate. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.8). The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the low U.S. fuel price scenario (0% real escalation in world oil prices). See Table 1.2.

TABLE I.10

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
LOW GROWTH SCENARIO[b]
1990 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[c] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[b] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	9	7	16	2	18	69	51	95	8320	422
Nova Scotia	Coal	33	5	38	5	43	69	26	75	6570	171
New Brunswick	Nuclear	27	3	29	4	33	69	36	85	7450	264
NPCC-New York:											
Quebec	Hydro	24	9	33	7	40	69	29	53	4600	133
Ontario	Nuclear	32	4	36	7	43	69	26	53	4600	121
MARCA:											
Manitoba	Hydro	33	26	59	14	73	58	-15	23	1970	-30
Saskatchewan	Coal	52	11	62	24	86	58	-28	23	1970	-56
WSCC-CANV:											
Alberta	Coal	22	5	27	14	40	73	32	75	6570	213
British Columbia	Hydro	14	6	20	10	30	73	43	95	8320	354

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[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Canadian capital costs are annuitized using a 7% real discount rate. The sum of individual entries may not equal the total due to rounding.

[b] Capacity factors are based on the matched low growth scenario for U.S. capacity and demand (from Table I.8).

[c] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the base case U.S. fuel price scenario (2% real escalation in world oil prices). See Table I.2.

TABLE I.11

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
LOW OIL PRICE AND GROWTH SCENARIO[b]
1990 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[b] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	9	7	16	2	18	59	41	95	8320	343
Nova Scotia	Coal	33	5	38	5	43	59	17	75	6570	190
New Brunswick	Nuclear	27	3	29	4	33	59	26	85	7450	193
NPCC-New York:											
Quebec	Hydro	24	9	33	7	40	59	20	53	4600	90
Ontario	Nuclear	32	4	36	7	43	59	17	53	4600	77
MARCA:											
Manitoba	Hydro	33	26	59	14	73	50	-23	23	1970	-46
Saskatchewan	Coal	52	11	62	24	86	50	-36	23	1970	-71
WSCC-CANV:											
Alberta	Coal	22	5	27	14	40	63	22	75	6570	147
British Columbia	Hydro	14	6	20	10	30	63	33	95	8320	270

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[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Canadian capital costs are annuitized using a 7% real discount rate. The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the low U.S. fuel price scenario (0% real escalation in world oil prices). See Table I.2. Capacity factors are based on the matched low growth scenario for U.S. capacity and demand (from Table F.8).

TABLE I.12

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
2000 STUDY YEAR
BASE CASE[b]

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[c] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)x(7)/1000
NPCC-New England:											
Newfoundland	Hydro	12	10	22	3	25	83	58	76	6670	388
Nova Scotia	Coal	38	6	44	6	50	83	34	75	6570	220
New Brunswick	Nuclear	32	3	35	5	40	83	43	76	6670	286
NPCC-New York:											
Quebec	Hydro	20	9	28	5	33	83	50	77	6710	337
Ontario	Nuclear	25	3	28	5	33	83	50	77	6710	337
MARCA:											
Manitoba	Hydro	18	13	31	7	38	70	32	50	4400	141
Saskatchewan	Coal	32	5	37	12	50	70	21	50	4400	91
WSCC-CANV:											
Alberta	Coal	25	6	30	16	46	88	43	75	6570	279
British Columbia	Hydro	15	8	24	12	36	88	52	89	7790	404

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[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.9). The sum of individual entries may not equal the total due to rounding.

[b] Capital costs are annuitized using a 7% real discount rate.

[c] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the base case U.S. fuel price scenario (2% real escalation in world oil prices). See Table I.2.

TABLE I.13

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
4 PERCENT DISCOUNT RATE
2000 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7) (6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)×(7)/1000
NPCC - New England:											
Newfoundland	Hydro	8	8	15	3	18	83	66	76	6670	439
Nova Scotia	Coal	35	5	40	5	44	83	39	75	6570	257
New Brunswick	Nuclear	24	3	27	4	31	83	53	76	6670	351
NPCC - New York:											
Quebec	Hydro	12	7	19	4	23	83	61	77	6710	406
Ontario	Nuclear	19	3	21	4	25	83	58	77	6710	391
MARCA:											
Manitoba	Hydro	11	10	21	6	27	70	43	50	4400	191
Saskatchewan	Coal	25	4	30	10	39	70	31	50	4400	136
WSCC-CANV:											
Alberta	Coal	21	4	25	12	38	88	50	75	6570	331
British Columbia	Hydro	10	7	17	10	26	88	62	89	7790	481

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[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.9). The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the base case U.S. fuel price scenario (2% real escalation in world oil prices). See Table I.2.

TABLE 1.14

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
10 PERCENT DISCOUNT RATE
2000 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC - New England:											
Newfoundland	Hydro	17	12	29	4	33	83	50	76	6670	333
Nova Scotia	Coal	42	7	49	7	56	83	27	75	6570	180
New Brunswick	Nuclear	41	4	45	6	51	83	32	76	6670	215
NPCC - New York:											
Quebec	Hydro	27	11	38	6	44	83	39	77	6710	262
Ontario	Nuclear	32	4	36	6	42	83	41	77	6710	277
MARCA:											
Manitoba	Hydro	25	17	41	9	50	70	20	50	4400	88
Saskatchewan	Coal	39	7	46	15	61	70	9	50	4400	40
WSCC-CANV:											
Alberta	Coal	29	7	35	19	54	88	34	75	6570	221
British Columbia	Hydro	21	11	32	15	47	88	41	39	7790	321

---

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.9). The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the base case U.S. fuel price scenario (2% real escalation in world oil prices). See Table 1.2.

TABLE I.15

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
LOW OIL PRICE[b]
2000 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[a] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC - New England:											
Newfoundland	Hydro	12	10	22	3	25	59	34	76	6670	229
Nova Scotia	Coal	38	6	44	6	50	59	10	75	6570	63
New Brunswick	Nuclear	32	3	35	5	40	59	19	76	6670	127
NPCC - New York:											
Quebec	Hydro	20	9	28	5	33	59	26	77	6710	176
Ontario	Nuclear	25	3	28	5	33	59	26	77	6710	176
MARCA:											
Manitoba	Hydro	18	13	31	7	38	50	12	50	4400	54
Saskatchewan	Coal	32	5	37	12	50	50	1	50	4400	3
WSCC-CANV:											
Alberta	Coal	25	6	30	16	46	63	17	75	6570	113
British Columbia	Hydro	15	8	24	12	36	63	27	89	7790	207

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Capacity factors are based on the matched mid growth scenario for U.S. capacity and demand (from Table F.9). The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the low U.S. fuel price scenario (0% real escalation in world oil prices). See Table I.2.

TABLE 1.16

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
LOW GROWTH SCENARIO[b]
2000 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[c] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[b] (%)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)×(7)/1000
NPCC - New England:											
Newfoundland	Hydro	10	8	19	3	22	83	62	89	7770	480
Nova Scotia	Coal	38	6	44	6	50	83	34	75	6570	220
New Brunswick	Nuclear	29	3	32	5	37	83	47	85	7450	349
NPCC - New York:											
Quebec	Hydro	41	18	59	11	70	83	13	36	3120	41
Ontario	Nuclear	49	7	56	11	67	83	16	36	3120	50
MARCA:											
Manitoba	Hydro	21	15	36	8	44	70	26	44	3810	100
Saskatchewan	Coal	35	6	41	14	55	70	15	44	3810	56
WSCC-CANV:											
Alberta	Coal	25	6	30	16	46	88	43	75	6570	279
British Columbia	Hydro	15	8	23	12	34	88	54	94	8240	444

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. The sum of individual entries may not equal the total due to rounding.

[b] Capacity factors are based on the matched low growth scenario for U.S. capacity and demand (from Table F.9).

[c] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the low U.S. fuel price scenario (0% real escalation in world oil prices). See Table 1.2.

TABLE I.17

POTENTIAL NET REVENUES FROM DEDICATED ENERGY EXPORTS[a]
LOW OIL PRICE AND GROWTH SCENARIO[b]
2000 STUDY YEAR

(1980 mills/kW.h Can. unless otherwise indicated)

U.S. Market: Exporting Province	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Capacity Factor[b] (%)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
NPCC - New England:											
Newfoundland	Hydro	10	8	19	3	22	59	38	89	7770	294
Nova Scotia	Coal	38	6	44	6	50	59	10	75	6570	63
New Brunswick	Nuclear	29	3	32	5	37	59	23	85	7450	171
NPCC - New York:											
Quebec	Hydro	41	18	59	11	70	59	-11	36	3120	-33
Ontario	Nuclear	49	7	56	11	67	59	- 8	36	3120	-25
MARCA:											
Manitoba	Hydro	21	15	36	8	44	50	- 6	44	3810	24
Saskatchewan	Coal	35	6	41	14	55	50	- 5	44	3810	-20
WSCC-CANV:											
Alberta	Coal	25	6	30	16	46	63	17	75	6570	113
British Columbia	Hydro	15	8	23	12	34	63	29	94	8240	235

[a] For a U.S. purchase of 1000 MW of capacity from a Canadian dedicated facility. Canadian capital costs are annuitized using a 7% real discount rate. The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the marginal cost of oil-fired generation in each region for the low U.S. fuel price scenario (0% real escalation in world oil prices). See Table I.2. Capacity factors are based on the matched low growth scenario for U.S. capacity and demand (from Table F.9).

TABLE 1.18

POTENTIAL NET REVENUES FROM INTERRUPTIBLE ENERGY EXPORTS[a]
BASE CASE[b]

(1980 mills/kW.h Can. unless otherwise indicated)

Exporting Province/ U.S. Market: Study Year	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Energy GW.h (8)	Total Net Revenue 1980 $M (9)=(8)x(7)/1000
New Brunswick/ NPCC-New England:										
1990	Coal	28	1	29	2	30	50	19	5000	97
2000	Nuclear	8	1	8	1	9	46	37	5000	185
Quebec/ NPCC-New York:										
1990	Hydro	1	1	2	1	3	36	33	5000	166
2000	Hydro	1	1	2	1	3	43	40	5000	201
Ontario/ NPCC-New York:										
1990	Coal	18	0	19	1	20	44	24	5000	122
2000	Nuclear	5	1	6	1	7	45	38	5000	191
Manitoba/ MARCA:										
1990	Hydro	1	1	2	1	3	30	28	5000	139
2000	Hydro	1	1	2	1	3	36	34	5000	168
British Columbia/ WSCC-CANV:										
1990	Hydro	1	1	2	2	4	38	35	5000	173
2000	Hydro	1	1	2	2	4	46	42	5000	210

[a] For an energy export of 5000 GW.h. The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the mid-point between the delivered cost of Canadian electricity and the marginal cost of domestic oil-fired generation in each region (see Table 1.7), for the base case U.S. fuel price scenario (2% real escalation in world oil prices).

TABLE 1.19

POTENTIAL NET REVENUES FROM INTERRUPTIBLE ENERGY EXPORTS[a] LOW FUEL PRICE[b]

(1980 mills/kW.h Can. unless otherwise indicated)

Exporting Province/ U.S. Market: Study Year	Generation Type	Generation Cost (1)	Canadian Transmission (2)	Border Cost (3)=(1)+(2)	U.S. Transmission (4)	Delivered Cost (5)=(3)+(4)	Demand Price[b] (6)	Unit Net Revenue (7)=(6)-(5)	Energy GW.h (8)	Total Net Revenue 1980 $MM (9)=(8)x(7)/1000
New Brunswick/ NPCC-New England:										
1990	Coal	28	1	29	2	30	45	15	5000	73
2000	Nuclear	8	1	8	1	9	34	25	5000	125
Quebec/ NPCC-New York:										
1990	Hydro	1	1	2	1	3	31	28	5000	142
2000	Hydro	1	1	2	1	3	31	28	5000	141
Ontario/ NPCC-New York:										
1990	Coal	18	0	19	1	20	40	20	5000	99
2000	Nuclear	5	1	6	1	7	33	26	5000	132
Manitoba/ MARCA:										
1990	Hydro	1	1	2	1	3	26	24	5000	119
2000	Hydro	1	1	2	1	3	27	24	5000	119
British Columbia/ WSCC-CANV:										
1990	Hydro	1	1	2	2	4	33	30	5000	148
2000	Hydro	1	1	2	2	4	33	29	5000	147

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[a] For an energy export of 5000 GW.h. The sum of individual entries may not equal the total due to rounding.

[b] The U.S. demand prices correspond to the mid-point between the delivered cost of Canadian electricity and the marginal cost of domestic oil-fired generation in each region (see Table 1.2), for the low U.S. fuel price scenario (0% real escalation in world oil prices).

TABLE I.20

POTENTIAL NET REVENUES TO CANADIAN UTILITIES UNDER ALTERNATIVE SCENARIOS[a] (1980 $MM Can.)

Dedicated Capacity:	
2000 Study Year	
4%	841
7%	419
10%	137
Dedicated Energy:	
1990 Study Year	
4%	2010
7%	
Base Case	1648
Low Oil Price	1204
Low Capacity/Demand Growth	1678
Low Oil Price and Growth	1229
10%	1256
2000 Study Year	
4%	2983
7%	
Base Case	2483
Low Oil Price	1148
Low Capacity/Demand Growth	2019
Low Oil Price and Growth	900
10%	1937
Interruptible Energy:	
1990 Study Year	
Base Case	697
Low Oil Price	581
2000 Study Year	
Base Case	955
Low Oil Price	664

---

[a] Total net revenues to Canadian utilities are calculated by summing the provincial net revenues in the last column of Tables I.3 through I.19. (All uneconomic sales/negative net revenues for individual provinces have been assigned a zero dollar value.) Base case results are highlighted.

Footnotes

[1] Basically, this surplus of U.S. replacement cost over delivered cost is available for distribution as follows:

(i) to Canadian utilities, in the form of export revenue above cost;
(ii) to American utilities, in the form of cost savings between replacement cost and the price of the import; and
(iii) to governments through taxation.

[2] A GW.h is equal to 1×10^6 kW.h.

[3] See note 31 in Chapter 4 for exceptions.

APPENDIX J

TRANSMISSION

Appendix J

TRANSMISSION

J.1 Transmission Costs

In this section the costs of bulk transmission associated with export sales of 1000 MW of capacity, and the rationale behind the costing approach adopted, are outlined. Dedicated capacity, dedicated energy and seasonal diversity interchange export sales would require additional transmission capacity on both sides of the border. In some areas new transmission lines would be required, while in others reinforcement of existing lines would be sufficient. For ease of analysis, we cost transmission on the basis of new transmission facilities between the generation source and the U.S. load centre, providing in some sense an upper bound on the transmission component of total cost. Because of the large transmission distances from the Canadian generation centres to the U.S. load centres under consideration, it is thought Direct Current (DC) transmission would be more appropriate than Alternating Current (AC) transmission for point to point bulk transmission.[1] Accordingly, the additional transmission capacity constructed is assumed to be ±400-±500 DC transmission. In contrast, we assume that interruptible energy sales involve the transfer of 'surplus' energy over existing (AC and DC) transmission lines.

Common to all classes of export sales are operation and maintenance (O & M) costs and costs associated with transmission losses. What follows is a description of the approach adopted for specifiying each of the three cost types. One should view the ensuing costs analysis as being broadly realistic for a 'representative' interconnection rather than being applicable to any specific interconnections being contemplated by Canadian or U.S. utilities. Detailed project level design specifications would be required to estimate costs for a particular interconnection. Because of the variance in unit transmission cost across regions and types of terrain, the estimation of transmission costs is more judgemental than that of site-specific generation costs.

J.1.1 Capital Costs

The primary components of a typical High Voltage Direct Current (HVDC) system consist of one or more bipolar lines, or bipolar cables, and two converter stations. One of the converter stations is operated as a rectifier in which AC energy is converted into DC energy and the other as an inverter in which DC energy is converted into AC. Normally a converter station is designed to operate in either mode since there is no major difference in the components required.

The major components of capital costs are the physical construction costs of terminals and lines. In addition, line costs should include the costs of acquiring right of way or land. Both terminal and line capital costs should include allowances for interest during construction (generally 3 - 4 years) and for contingencies.

In Table J.1 are presented a range of estimated 1980 terminal and line HVDC transmission capital costs as determined from a cursory survey of Canadian projects under design study. The determination of transmission capital costs for a particular project is highly dependent upon several factors including:

- difficulty of terrain, regional climatic conditions, remoteness, etc.;
- distance transmitted;
- line specifications (conductor size, number of bundles, etc.); and
- terminal specifications (valves, transformers, filters, synchronous condensers if necessary, etc.).

Based on the previous projections, in the analysis we adopt a single inclusive (two) terminal 1980 capital cost of $150 per kW and a single inclusive line capital cost of $350,000 per kilometre, with both unit costs expressed in 1980 Canadian dollars. Real escalation of one percent per year for the period 1980 - 2000 is applied to both terminal and line capital costs (i.e., the cost of transmission line and terminal construction is assumed to increase one percent faster than the overall inflation rate).

J.1.2 Operating Costs

Operating costs (operation and maintenance costs) for transmission lines are small relative to capital costs. One convention, and that adopted in this study, is to estimate annual operating cost as 1 percent of total transmission capital cost.[2]

TABLE J.1

HVDC TRANSMISSION CAPITAL COST PROJECTIONS IN 1980[a]

Source	Region	Firm Capacity and DC Voltage Specification	Line Cost				Terminal Cost (For Two)		
			Cost (1980 $/km)	Includes			Cost (1980 $/kW)	Includes	
				IDC[b]	ROW[c]	CONT[d]		IDC[b]	CONT[d]
Bechtel Report	Labrador	1000 MW, ±400-kV	320 000	No	Yes	25%	159	No	Yes
Bechtel Report	New York	1000 MW, ±400-kV	247 000	No	Yes	20%	159	No	Yes
Hydro-Quebec	New England	600 MW, ±450-kV	247 000	?	?	?	100	?	?
RCEPP Planning	Ontario	±450-kV	188 000	?	?	?	119	?	?
IPACE Study	Ontario-Quebec	1000 MW, ±450-kV	290 000	Yes	?	15%	115-140	Yes	15%
IPACE Study	Manitoba-Alberta	1000 MW, ±500-kV	387 000	Yes	?	15%	115-140	Yes	15%
B.C. Hydro	British Columbia	4800 MW, ±600-kV	322 000	No	No	No	125	No	No

SOURCES: (This table has been derived from the following:)

(1) Bechtel, *Labrador Power Transmission Alternatives (Conformed Report)*, Report Prepared for the Power Authority of the State of New York and Newfoundland and Labrador Hydro, July 1980. (2) Unpublished Hydro-Quebec utility information. (3) Ontario Hydro, "Transmission Planning Processes," Memorandum to the (Ontario) Royal Commission on Electric Power Planning With Respect to the Public Information Hearings (Toronto: Ontario Hydro, July 1980). (4) IPACE Networks Study Group, *An Evaluation of Strengthened Interprovincial Interconnections of Electric Power Systems*, Volume 2, Report to the Interprovincial Advisory Council on Energy, October 1978. (5) Personal communication, B.C. Hydro Transmission Planning Department. Raw data given in $1981 was converted to $1980 assuming 15 percent inflation.

[a] Costs were taken from the documented reports and converted to 1980 Canadian dollars utilizing transmission construction price indexes for 1976-1980 from Canada, Statistics Canada, *Construction Price Indexes*, Catalogue 62-007 Monthly, and utilizing U.S./Canada exchange rate information from Canada, Bank of Canada, *Bank of Canada Review*.

[b] Interest During Construction

[c] Right of Way

[d] Contingency

Operating costs for existing lines do not include possible 'wheeling' charges. These refer to payments to neighbouring regions for the use of transmission through their territory.

J.1.3 Transmission Losses

In addition to capital and operating costs of transmission lines a cost is incurred due to transmission losses between the Canadian generation facility and the U.S. region. The bulk transmission losses represent thermal losses and are mainly a result of line resistance (line losses) and station losses. Some corona (visible glow of the line) losses would occur but under normal weather conditions these would be minimal.[3]

The magnitude of line losses (per line) is determined by:

- line specifications (voltage, conductor size, number of circuits per line, etc.);
- power transmitted (load level); and
- transmission distance.

For a fixed voltage rating, conductor specification and number of circuits per line,

$$\text{Losses} \ \alpha \ I^2R$$

where

I = load level
R = resistance (transmission distance)

Station losses in turn are related mainly to terminal specifications such as maximum power rating. They can vary somewhat with the load level. As an approximation, we view line losses as the variable component and station losses as the fixed component of losses over a transmission system.

In a real sense, a utility 'can choose the losses to be what they want them to be' through appropriate choice of system design parameters such as voltage level and conductor size. Table J.2 summarizes the results of a brief survey of DC transmission line loss experience.

For the 1000 MW capacity and ±400-500 kV DC line case under consideration, and under normal design conditions, available experience suggests a bulk transmission loss on the order of 0.6 percent per 100 kilometres per line.[4]

TABLE J.2

CANADIAN DC TRANSMISSION LOSS EXPERIENCE

Source	Voltage	Line Rating	Line Length	Losses for 1000 MW Firm	
				Losses	Percent Losses/ 100 km
Bechtel					
Route 1	735 kV AC	?	2085 km	130 MW[a]	0.6%
Route 2	735 kV AC/ ±400 kV DC	?	1390 km 620 km	135 MW[a]	0.7%
Nelson River Main Line	±500 kV DC	1800 MW	935 km	52 MW[b]	0.6%
Nelson River Secondary Line	±450 kV DC	1620 MW	935 km	66 MW[c]	0.7%
Liard	±600 kV DC	2400 MW	1335 km	56 MW[d]	0.4%

SOURCE: (1) Bechtel, Labrador Power Transmission Alternatives (Confirmed Report), Report prepared for the Power Authority of the State of New York and Newfoundland and Labrador Hydro, July 1980. (2) Personal communication with Manitoba Hydro. (3) Personal communication with British Columbia Hydro and Power Authority.

[a] Assumes an 80% capacity factor.

[b] At full transmission capacity, line losses would be 94 MW and station losses would be 36 MW. At 1000 MW firm and 75% capacity utilization, line losses would be reduced to 16 MW $\left(\frac{750^2 \times 94}{1800^2}\right)$.

[c] At full transmission capacity, line losses would be 90 MW and station losses would be 47 MW. At 1000 MW and 75% capacity utilization, line losses would be reduced to 19 MW $\left(\frac{750^2 \times 90}{1620^2}\right)$.

[d] At full transmission capacity, line losses would be 84 MW and station losses would be 48 MW. At 1000 MW and 75% capacity utilization, line losses would be reduced to 8 MW $\left(\frac{750^2 \times 84}{2400^2}\right)$.

The following transmission loss multiplier is employed:

$$L = \frac{.006\ R/100}{1 - .006\ R/100}$$

where

L = transmission losses
R = transmission distance

Consequently, the loss multiplier times energy delivered equals the transmission loss. The effect of transmission losses is to require a greater amount of Canadian energy to be generated to satisfy U.S. demand requirements than if no losses occurred. In the analysis transmission losses are costed at the unit operating cost of generation.

J.2 Transmission Distances

Tables J.3a and J.3b present estimated transmission distances from hypothetical Canadian generating sources to selected major U.S. load centres, for use in costing dedicated capacity exports, dedicated energy exports, and seasonal diversity interchange. These three types of sale presume the construction of new transmission facilities. Transmission routes have been calculated along existing high voltage lines and interconnections, where possible, and are intended only to be representative of the distances involved.

TABLE J.3a

DISTANCES FROM CANADIAN GENERATING STATIONS
TO U.S. LOAD CENTRES[a]
(kilometres)

NPCC-New England				
Province	Newfoundland	Nova Scotia	New Brunswick	
Study year	1990, 2000	1990, 2000	1990, 2000	
Generating Source	Gull Island	Halifax	Point Lepreau	
Station to Border	1370	545	275	
Border to Boston, MA	305	565	565	
Total	1675	1110	840	
NPCC-New York				
Province	Quebec	Quebec	Ontario	New Brunswick
Study Year	1990	2000	1990, 2000	2000
Generating Source	NBR	La Romaine	Bruce	Point Lepreau
Station to Border	950	1160	300	275
Border to New York, NY	610	610	595	940
Total	1560	1770	895	1215
MARCA				
Province	Manitoba	Manitoba	Saskatchewan	
Study Year	1990	2000	1990, 2000	
Generating Source	Limestone	Conawapa	Courval	
Station to Border	1150	1190	340	
Border to Minneapolis, MN	540	540	1045	
Total	1690	1730	1385	

[a] Figures are rough estimates along existing or hypothetical high voltage transmission lines.

TABLE J.3b

DISTANCES FROM CANADIAN GENERATING STATIONS TO U.S. LOAD CENTRES[a]
(kilometres)

WSCC-CANV

Province	Alberta	B.C.	B.C.
Study year	1990, 2000	1990	2000
Generating Source	Red Deer	Peace Site C	Iskut-Stikine
Station to Border	595	1015	1350
Border to Los Angeles, CA	1995	2060	2060
Total	2590	3075	3410

MACC

Province	Quebec
Study Year	2000
Generating Source	NBR
Station to Border	950
Border to Washington, DC	920
Total	1870

MAIN

Province	Ontario
Study Year	2000
Generating Source	Bruce
Station to Border	360
Border to Chicago, Ill.	380
Total	740

---

[a] Figures are rough estimates along existing or hypothetical high voltage transmission lines.

Footnotes

[1] DC transmission involves higher terminal costs and lower line costs than comparable AC transmission. DC transmission is usually subject to a greater number of short-term outages than is AC transmission. It has sometimes been argued that at transmission distances greater than 650 kilometres (400 miles) bulk DC transmission becomes preferable to AC transmission. However, this 'rule' is overly simplistic and in practice the choice of transmission type depends upon design level considerations. For a discussion of DC transmission advantages and disadvantages relative to AC transmission see Ontario Hydro, "Transmission Planning Processes," Memorandum to the (Ontario) Royal Commission on Electric Power Planning with Respect to the Public Information Hearings (Toronto: Ontario Hydro, June 1976), pp. 54-57, and Bechtel, Labrador Power Transmission Alternatives (Conformed Report), Report prepared for the Power Authority of the State of New York and Newfoundland and Labrador Hydro, July 1980, Appendix A.

[2] See United States, Federal Power Commission, Transmission Technical Advisory Committee, 1970 National Power Survey, Part IV and Alberta, Electric Utility Planning Council, Power Development Evaluation Committee, "Generation Alternatives for 1982 - 1988" (Calgary: Electric Utility Planning Council, April 1976).

In costing transmission O & M costs for interruptible energy sales over existing AC and DC lines, 1 percent of the capital cost of new DC transmission is employed as a proxy.

[3] Ontario Hydro, "Transmission Planning Processes," p. 18.

[4] In the analysis, station losses, although actually fixed with respect to transmission distance and load level, are implicitly expressed on a unit energy basis per 100 kilometres. The figure cited here corresponds roughly to one percent per 100 miles (see Table J.2).

APPENDIX K

A DESCRIPTION OF THE ECONOMIC IMPACT ANALYSIS

Appendix K

A DESCRIPTION OF THE ECONOMIC IMPACT ANALYSIS

K.1 The Input-output Approach

Input-output analysis is the analytical tool chosen to examine the impact of the export of electricity and other commodities. The major attribute of input-output analysis is that it provides an extremely comprehensive and extensive mechanism for describing inter-industrial linkages.

An input-output table provides a 'snapshot' of the economy; that is, it gives a detailed view of the economy at one moment in time. An input-output table (or model) is a set of linear formulations which show the interdependence of economic activity. This interdependence derives from the fact that the output of one industry may be used as an input to another industry and that the output of the latter may be used as input to the former. The full interdependence of the economy can be better appreciated by noting that an increment to the final demand for one commodity can result in increased output of virtually all industries in the economy.

The basic table of the input-output system is the transactions table. The rows of this table show how the output of each industry is distributed among other industries as intermediate goods and final demand. The columns show the inputs to each industry of intermediate goods from other industries and of factor services.

The structure of Statistics Canada's input-output models is shown in Figure K.1. The Interprovincial Input-output Model links 121 input-output models of this type representing the 10 provinces and the territories and showing the structural and trade linkages between each pair of regions.

An integral part of input-output analysis is the determination of direct, indirect and induced effects of project expenditures. Direct effects comprise the effects arising from 'first round' expenditures on labour and on supply purchases to meet the initial increment in demand. Indirect effects are those arising from meeting the input requirements of these first round suppliers and the second and all subsequent round suppliers. The indirect effects will generally permeate

	Commodities	Industries	Final Demand								Total
			PC	FCF	Inv	GGCE	XD	XR	Less M	Less GR	
Commodities		U	F				X				q
Industries	V										g
Commodity indirect taxes Other indirect taxes Subsidies Wages and salaries Supplementary labour income Net income of unincorporated business Surplus		Y	YF								Gross Domestic Product at market Prices
Total	q′	g′	Expenditure on Gross Domestic Product at Market Prices								

SOURCE: Canada Statistics Canada, The Input-Structure of the Canadian Economy, Catalogue 15-201E, June 1980, p. 9.

NOTE:

Final Demand Categories and Imports

PC: Personal expenditure on goods and services
FCF: Fixed capital formation, business and government
Inv: Value of physical change in inventories
GGCE: Gross government current expenditure goods and services
XD: Exports of domestic goods and services
XR: Re-exports of goods and services
M: Imports of goods and services
GR: Government revenue from sale of goods and services

Notation

V: is a matrix of the values of outputs
U: is a matrix of the values of intermediate inputs
q: is a vector of the values of total commodity outputs
g: is a vector of the values of total industry outputs
Y: is a matrix of values of primary inputs of industries
F: is a matrix of the values of the following categories of final demand: PC, FCF, Inv and GGCE
YF: is a matrix of the values of the primary inputs associated with final demand categories
X: is a matrix of the value of domestic exports and re-exports

FIGURE K.1: THE ACCOUNTING FRAMEWORK OF CANADIAN INPUT-OUTPUT TABLES

the economy, causing increased output and employment in many industries. Induced effects are those generated by the spending and respending of household income (wages and salaries, supplementary labour income and net income of unincorporated business). Part of the initial expenditures will accrue to households. In addition, there will be payments to households as part of the indirect effects. As these funds are respent, new demands will be placed on industry.

K.2 Assumptions

All coefficients in the Statistics Canada Interprovincial Input-output Model are simple proportions based on the 1974 structure of the Canadian economy. This assumption of simple proportionality implies that marginal changes are equal to average changes. The technical coefficients indicate a production process of fixed relations between inputs and outputs which implies constant returns to scale (i.e., a doubling of inputs leads to a doubling of output). Further it implies that the elasticity of substitution is zero, that is, that the production process cannot be adjusted, for example, to use more of cheaper commodities or factors when their relative prices decrease. There is no technical change. Technology is embodied in the coefficients and cannot be altered. The market share assumption is that demand for commodities is allocated among industries by a fixed set of market shares. Included is an import component. Both imports of commodities from outside the province and imports from outside the country are a fixed share of total provincial demand.

The input-output model is static; that is, time is not explicit. The use of the model involves the comparison of output, income and employment before and after the construction and operation of the electricity generating facilities. Neither the amount of time for the effects to be fully worked out nor the time paths of the relevant variables is obtained from the model. Only a total impact is calculated. Annual variations which may occur during the construction and operation phases are dissembled.

Implicit in the model is the absence of supply constraints. Supply is perfectly elastic. Employment comes from the unemployed, new labour force entrants, or immigration. Raw materials are either available domestically in limitless quantities or can be imported. Additionally it is assumed that there is no displacement of output from other industries due to the stimulus in (export) final demand. In sum, it is assumed that 'gross' and 'net' impacts on the economy are essentially the same. Another implication is that the model says nothing about inflationary effects created by industry demands.

The input-output model deals only with flows; stocks are not represented. It is assumed that increased production can be attained with the existing capital stock. Capacity must be available so that no investment need take place.

In addition to the standard assumptions cited above, there are myriad assumptions required in the actual calculation of the input-output model coefficients. Many of these merely reflect the model builder's judgement and are adequately documented in Statistics Canada publications.[1]

K.3 Definition of Impact Measures

K.3.1 Income

Gross Domestic Product is the most comprehensive measure of the impact on national and provincial income produced by a stimulus in final demand such as an increase in exports. Gross Domestic Product (GDP) measures the net value of production or the amount of income arising within the geographical boundaries of a region, irrespective of whether the factors of production (labour and capital) involved are resident or non-resident. The net value of production represents the gross return to labour (pre-tax household income) and the gross return to capital or surplus (pre-tax corporation profits, capital consumption allowances and interest payments). In contrast, Gross National Product (GNP) measures the return to resident factors only and excludes the return to non-resident factors. Information to distinguish clearly between the returns to resident and non-resident factors is generally inadequate except at the national level. Furthermore, the available statistics do not permit a distinction to be made between resident and non-resident factors in determining industry output.

Gross Domestic Product at Factor Cost measures GDP at producers' prices. Gross Domestic Product at Market Prices includes indirect taxes and subsidies and is thus the net value of production at price levels at which goods and services actually change hands. Table K.1 shows the relationships between GNP and GDP at Market Prices and Factor Cost for Canada in 1980.

TABLE K.1

RELATIONSHIP BETWEEN GROSS NATIONAL PRODUCT AND GROSS DOMESTIC PRODUCT AT MARKET PRICES AND AT FACTOR COST, FOR CANADA IN 1980

	1980 (millions of dollars)
Gross National Product at Market Prices	291,869
Deduct:	
Investment income received from non-residents	-3,387
Add:	
Investment income paid to non-residents	11,345
Gross Domestic Product at Market Prices	299,827
Deduct:	
Indirect taxes less subsidies	-29,012
Residual error of estimate	127
Gross Domestic Product at Factor Cost	270,942

SOURCE: Canada, Statistics Canada, National Income and Expenditure Accounts, Catalogue 13-001 Quarterly, First Quarter 1982.

GDP is a measure of the unduplicated value of production (net production). It is the gross value of production of firms less the purchases of goods and services from other firms. This difference between the value of outputs and the value of inputs is called value added. Value added may also be seen as the payment to factors of production such as wages and salaries.

K.3.2 Employment

The employment impacts are cited in man-years. The input-output model calculates employment by multiplying 1979 provincial job-to-gross output ratios and the 1974 gross output estimates. Conversion to a 1980 basis was accomplished by applying an inflation factor calculated from the price index of Gross Domestic Product.

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[1] Canada, Statistics Canada, The Input-Output Structure of the Canadian Economy, Catalogue 15-201E, June 1980.

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GLOSSARY

GLOSSARY OF ELECTRICITY TERMS

BASE LOAD GENERATION: generation which operates or is capable of operating at full output most of the time that it is available.

BULK TRANSMISSION: the main transmission lines which deliver power from generating stations to terminal stations.

CAPACITY: the numerical measure used to indicate the extent to which a component of a power system can fulfill its function. For example, a generator has a certain capacity (measured in watts) to produce power.

CAPACITY FACTOR: the ratio of the average load on a piece of electric equipment over a certain time period to the capacity rating of the equipment.

CONVERSION FACILITIES: facilities for converting between alternating current (AC) power and direct current (DC) power in a high voltage direct current (HVDC) system. Two converter stations are required, one to change from AC to DC by rectifiers and the other to change from DC to AC by inverters.

DEMAND: the power (measured in watts) or energy (measured in watt-hours) required to supply the system load at any given time.

DIVERSITY: the difference between the coincident peak load for a group of customers (e.g., two systems combined) and the sum of the non-coincident peak loads of the individual customers (e.g., the individual systems).

ENERGY: available heat in electricity measured in kilowatt-hours, where one kilowatt-hour is equivalent to 3412.97 Btu.

GENERATING UNIT: all the facilities at a generating station which are associated with a generator, and which are needed if the generator is to produce power.

GIGAWATT (GW): 1×10^6 kilowatts.

GIGAWATT-HOUR (GW.h): 1×10^6 kilowatt-hours.

HYDROELECTRIC POWER STATION: a power station which generates electricity from hydraulic sources. The water rotates turbines connected to generators.

KILOVOLT (kV): 1000 volts.

KILOWATT (kW): 1000 watts.

KILOWATT-HOUR (kW.h): 1000 watt-hours.

LOAD: the amount of electric power delivered at any specified point or points on a system.

LOAD CURVE: a charted curve showing power (in kilowatts) supplied, plotted against time of occurrence, and showing the variation in load over a specific time period.

LOSSES: the power consumed by the system itself due to the inefficiency of transmission lines, transformers, etc.

MARGINAL GENERATING UNITS: generating units which respond to an increment or decrement in required system energy over a given time period.

MEGAWATTS (MW): 1×10^3 kilowatts.

MEGAWATT-HOURS (MW.h): 1×10^3 kilowatt-hours.

MILL: one-tenth of a cent.

PEAK LOAD: the maximum average load during a time interval of specified duration (e.g., 20 minutes) occurring during a given period of time (e.g., a day).

PEAK LOAD GENERATION: generation which normally operates during daily peak periods. At other times it is shut down or operated at minimum safe loadings.

RESERVE MARGIN: the excess of installed capacity over forecasted peak load designed to provide against generator outages (both planned and unplanned).

SUMMER PEAK: the maximum load on a system during a specific demand interval in the summer, or cooling, season.

THERMAL POWER STATION: a power station which generates electricity from thermal sources. A thermal plant may use fossil-fuelled combustion turbines or nuclear steam turbines.

VOLT: the basic unit for measuring voltage.

WATT: the basic unit for measuring power.

WATT-HOUR: the basic unit for measuring energy.

WINTER PEAK: the maximum load on a system during a specific demand interval in the winter, or heating, season.

SOURCES: C. Lusk, "Glossary of Terms," Draft Paper to the Rates and Load Studies Section of the Canadian Electrical Association (CEA), Fall Meeting, Toronto, September 21, 1981; and Ontario Hydro, "Memorandum to the (Ontario) Royal Commission on Electric Power Planning with Respect to the Public Information Hearings" (Toronto: Ontario Hydro, May 1979).

GLOSSARY OF INTERCONNECTION TERMINOLOGY

CAPACITY POWER/EMERGENCY ENERGY: capacity and/or energy provided on an hourly or daily basis to supplement the generating capability of the receiving system during periods of temporary capacity deficiencies. Normally hour-by-hour negotiations are required, and a receiving system must make other arrangements within an hour after notice that the emergency delivery will be curtailed. Charges are typically the incremental cost of the supplying system plus a percentage adder.

DEDICATED CAPACITY*: capacity and associated energy from an export-dedicated facility to displace new (coal-fired or nuclear) base load capacity in the purchasing system. Power is guaranteed under medium or long-term contract. Delivery must be reliable since the purchaser foregoes the installation of domestic base load capacity.

DEDICATED ENERGY*: capacity and associated energy from an export-dedicated facility to displace existing oil-fired generation in the purchasing system. Power is guaranteed under medium or long-term contract.

FIRM POWER: capacity and/or energy that has the characteristic such that the supplier is obligated to deliver capacity or energy as scheduled for an extended period.

INADVERTENT ENERGY: the difference between actual and scheduled energy flow due to inadvertent control errors.

INTERCONNECTION: a transmission line for the movement of power between adjacent electrical systems.

INTERRUPTIBLE ECONOMY ENERGY: energy (with no capacity commitment) delivered on a short-term basis to displace higher cost generation when the receiving party has adequate generation of its own. Delivery is not firm and may be terminated on short notice. Any savings achieved are normally shared by the two parties.

OPERATING/SPINNING RESERVE: excess generating capacity held available on very short notice (i.e., within an hour) by one system for use by another system in satisfying its operating reserve requirements. A capacity charge will be made.

SEASONAL DIVERSITY INTERCHANGE: capacity and/or energy exchanged between utilities with annual peak loads in different seasons (i.e., summer versus winter). Supplier is obligated to deliver capacity and energy as scheduled unless delivery will jeopardize the supply to his own customers. In this study, diversity interchange is further specified to displace new capacity in expansion plans.

SHORT-TERM FIRM POWER: capacity and/or energy supplied for a specified period, usually of one or more weeks, to supplement the purchaser's peak generating capability.

STORAGE TRANSFER/BANKING: hydroelectric energy temporarily held in reservoir by another system.

TERTIARY: a catchall phrase for miscellaneous transactions which cannot be categorized under other classifications in interconnections agreements.

UNIT POWER: capacity and/or energy from a specific generating unit or facility which is dedicated to the buyer over an extended period. The purchaser pays a proportionate share of the fixed and operating costs of the unit and assumes the risks of interrupted supply.

WHEELING/TRANSMISSION SERVICE: the use of the transmission facilities of one system to transfer capacity and energy for another system. Charges are usually made and may include a factor for losses, a transmission capacity charge and an energy charge proportionate to the savings from the transaction.

SOURCES: Canada, Department of Energy, Mines and Resources and United States, Department of Energy, Canada/United States Electricity Exchanges (Ottawa: Energy, Mines and Resources Canada, May 1979); W. G. Chandler, "Summary of Interconnection Terminology," Paper Presented to the System Planning and Operation Section of the Canadian Electrical Association (CEA), Spring Meeting, Toronto, March 1976; and Chapter 1.

*As defined in this study. All other definitions refer to transactions currently in use.

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